STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

ORDER ESTABLISHING AN ALLOCATED COST OF SERVICE METHODOLOGY FOR STANDBY AND BUYBACK SERVICE RATES AND ENERGY STORAGE CONTRACT DEMAND CHARGE EXEMPTIONS

Issued and Effective: March 16, 2022

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At a session of the Public Service Commission held in the City of Albany on March 16, 2022

COMMISSIONERS PRESENT:

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

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(Issued and Effective March 16, 2022)

BY THE COMMISSION:

INTRODUCTION

On November 25, 2020, Department of Public Service Staff (Staff) and the New York State Energy Research and Development Authority (NYSERDA) issued a Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates (ACOS Whitepaper). The ACOS Whitepaper includes a number of recommendations to improve Standby and Buyback Service rates, including a standardized methodology for developing an Allocated Cost of Service (ACOS) study, the results of which would then be used to determine Customer Charges, Daily As-Used Demand Charges, and Contract Demand Charges for investor-owned electric utilities in New York.[1] The ACOS Whitepaper also proposes to implement a limited exemption from paying Buyback Service Contract Demand Charges for stand-alone energy storage systems.

In this Order, the Public Service Commission (Commission) adopts a modified methodology of allocating costs as compared to the method proposed in the ACOS Whitepaper by simplifying various components and standardizing the methodology statewide. This Order also adopts a modification to Staff's proposed limited exemptions to Buyback Service Contract Demand Charges for stand-alone energy storage systems. This Order, along with the Order Directing Standby and Buyback Service Tariff Filings that is being issued contemporaneously in this proceeding, resolve the many outstanding issues related to improvements in Standby and Buyback Service rates. As discussed further below, the Joint Utilities are directed to file draft tariffs incorporating the directives contained herein for the Commission's consideration.

BACKGROUND

In the 2019 Standby Rate Order, the Commission initiated a number of efforts to improve Standby and Buyback Service rates, including requiring that: 1) each utility shall develop Standby Service rates for mass-market customers;[2] 2) each

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[1] The electric utilities include Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas & Electric Corporation (RG&E) (collectively, the Joint Utilities, utilities, or JU).

[2] Mass market customers include residential and small commercial customers that are not billed on the basis of demand.

utility shall offer applicable Standby Service rates as a voluntary rate option; 3) Central Hudson, Con Edison, NYSEG, RG&E and O&R shall develop an ACOS study; 4) Central Hudson, National Grid, NYSEG, RG&E, and O&R shall develop more granular Daily As-Used Demand Charges; 5) each utility shall modify the Reliability Credit eligibility requirements to exclude customers whose generating equipment is eligible to receive compensation under the Value of Distributed Energy Resources (VDER) Value Stack tariff; 6) Central Hudson, National Grid, NYSEG, RG&E, and O&R shall implement the Multi-Party Campus Offset Tariff; 7) National Grid, NYSEG, and RG&E shall standardize the application of the buyback service Customer Charge and Contract Demand Charge; 8) Con Edison and O&R shall make tariff modifications requiring the purchase of Unforced Capacity (UCAP) from Buyback Service customers, and that all utilities implement a 5 megawatt (MW) cap for such purchases; 9) Con Edison shall implement a reduction in its Buyback Service Contract Demand Charge related to transformer costs for customers taking service at primary voltage; and 10) customers who install energy storage technologies shall continue to pay applicable Contract Demand Charges required under Standby and Buyback Service.[3]

To comply with the 2019 Standby Rate Order, the Commission required the utilities to make two filings. First, for implementing certain modifications with minimal rate or revenue impacts, the Commission required the utilities to file amended tariff leaves to become effective on July 1, 2019 (Tariff Filing). As part of the Tariff Filing, the Commission directed the utilities to file tariff amendments allowing

[3] 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).

customers in demand-metered service classes to voluntarily participate in Standby rates, modifying eligibility for the Reliability Credit, and requiring utilities to purchase up to 5 MW of UCAP through Buyback Service.

Second, for implementing other modifications with greater rate or revenue impacts, the Commission required the utilities to file an ACOS Study and associated draft tariff leaves in September 2019 (September 2019 Filing).[4] The Commission required the draft tariff leaves to include updated Standby and Buyback Service rates for existing eligible service classifications; implement new Standby rates for mass market customers; include seasonal Daily As-Used Demand Charges with an Off-Peak, On-peak, and Super-Peak periods during the summer season; include a Multi-Party Campus Offset Tariff option; and standardize Buyback Service terms, ensuring that these customers are paying applicable Customer Charges and Contract Demand Charges.

The utilities made their Tariff Filings and September 2019 Filings as required by the 2019 Standby Rate Order.[5] Two stakeholder forums to discuss the utilities' ACOS Studies and draft tariffs were held, on November 19, 2019,[6] and on

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[4] National Grid's then-current Standby and Buyback Service rates were already based on that Company's ACOS Study filed as part of its 2017 rate proceeding in Case 17-E-0238.

[5] The tariff leaves went into effect on July 1, 2019.

[6] Case 15-E-0751, Notice Announcing Standby Rate Design Stakeholder Form and Soliciting Comments (issued November 5, 2019).

February 7, 2020.[7] In addition, comments were requested on the September 2019 Filing by February 28, 2020.[8]

ACOS WHITEPAPER

In the ACOS Whitepaper, Staff noted that the ACOS Studies developed for the September 2019 Filing result in inconsistent allocations of cost categories among customer classes. Staff concluded that the studies did not sufficiently meet the Commission's directive for consistency in approaches. Staff noted that the utilities employed several different combinations of four approaches for allocating costs into shared and local categories in their respective ACOS Studies.[9] In addition, Staff noted that some of the utilities allocated costs separately for each Federal Energy Regulatory Commission (FERC) Account, while others aggregated the costs from multiple FERC Accounts by function. Instead of employing one of the many methodologies proposed by the utilities, Staff recommends an alternative that is consistent and standardized.

The ACOS Whitepaper recommends a standardized, five-step process which incorporates a decision tree to determine how embedded costs are to be allocated to the shared, local, and customer cost categories (Decision Tree methodology).[10] In addition to the proposed Decision Tree methodology, Staff recommends that the Commission implement a limited exemption

[7] Case 15-E-0751, Notice Announcing Second Standby Rate Design Stakeholder Forum (issued January 23, 2020).

[8] Case 15-E-0751, Notice Extending Comment Period Related to Allocated Cost of Service Studies, and Standby and Buyback Rates (issued December 24, 2019).

[9] ACOS Whitepaper, pp. 7–8.

[10] A decision tree is a series of yes or no answers mapped to various outcomes.

from Buyback Service Contract Demand Charges for stand-alone energy storage systems that export electricity to the grid (Buyback Exemption).

Due to the complexity of the recommendations in the ACOS Whitepaper, as well as the detailed comments on each provided by stakeholders, this Order is organized to first address the ACOS Whitepaper proposals related to the Decision Tree methodology. Second, the impact of rate design changes resulting from updated Standby Service rates is addressed, followed by discussion of the Buyback Exemption.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) was published in the State Register on December 23, 2020 [SAPA No. 15-E-0751SP34]. The deadline for comments pursuant to the Notice was February 22, 2021, although an extension was granted to file initial comments until March 8, 2021, and reply comments by March 22, 2021.[11] Subsequently, an extension was granted to file reply comments on the ACOS Whitepaper by April 12, 2021.[12]

Additionally, comments were solicited by August 6, 2021, regarding an alternative ACOS methodology proposed by the Joint Utilities.[13] The JU filed a description of their Alternate Allocator Methodology (AAM) Proposal (AAM Proposal) on July 29, 2021, as was discussed during the Third Technical Conference

[11] Case 15-E-0751, Notice Announcing Technical Conference and Extending Comment Period (issued February 5, 2021).

[12] Case 15-E-0751, Notice Extending Comment Period (issued March 17, 2021).

[13] Case 15-E-0751, Notice Announcing Technical Conference and Establishing Comment Period (issued July 6, 2021).

held on July 22, 2021. The deadline for comments on the JU's proposal was subsequently extended until August 20, 2021.[14]

A summary of all stakeholder comments received is included in the Appendix to this Order, while each of the comments are considered where relevant to the topics discussed in the body of this Order. The following summarizes the stakeholders responding to the various deadlines.

Initial comments responsive to the March 8, 2021 comment deadline were submitted by Advanced Energy Economy Institute, the Alliance for Clean Energy New York (ACENY) and the Advanced Energy Management Alliance (AEMA) (collectively, AEEI); Borrego Solar Systems, Inc. (Borrego); the City of New York (City); Environmental Defense Fund (EDF); GlidePath Development LLC (GlidePath); the Joint Utilities and Long Island Power Authority (LIPA) (collectively, JU); MicroGrid Networks, LLC (MGN); Multiple Intervenors (MI); New York Battery and Energy Storage Technology Consortium, Inc. (NY-BEST); New York Energy Consumers Council, Inc. (NYECC); Soltage LLC (Soltage); and, the New York State Department of State Utility Intervention Unit (UIU).

Reply comments responsive to the April 12, 2021 comment deadline were submitted by AEEI; the City; the JU; Northeast Clean Heat and Power Initiative (NECHPI); CertainSolar, Inc. d/b/a NineDot Energy (NineDot); and, NY-BEST.

With respect to the JU's AAM Proposal, comments responsive to the August 20, 2021 comment deadline were submitted by AEEI,[15] the City, JU, MI, NECHPI, NineDot, NY-BEST,

[14] Case 15-E-0751, Notice Extending Comment Period (issued August 5, 2021).

[15] AEMA submitted its August 20, 2021 comments collectively with NY-BEST instead of AEEI.

NYECC and the Metropolitan Transportation Authority (MTA) (NYECC/MTA), and UIU.

In addition, on September 2, 2021, the JU filed unsolicited reply comments responding to comments on its AAM Proposal.[16] On September 20, 2021, NY-BEST, MI, the City, AEEI, ACENY, and AEEI (collectively, the Sur-reply Parties) submitted a sur-reply addressing the JU's September 2, 2021 reply comments.[17]

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

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[16] LIPA was not included in the JU's September 2, 2021 comments.

[17] The JU's September 2, 2021 reply comments and the Sur-Reply Parties' September 20, 2021 sur-reply comments are collectively referred to as the September 2021 comments.

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

Decision Tree Methodology

1. Staff Proposal

Staff's Decision Tree methodology is a series of eight questions, resulting in determinations of what portion of a given cost should be considered customer, shared, or local, and thereafter form the basis for the revenues which should be recovered through Customer Charges, Daily As-Used Demand Charges, or Contract Demand Charges, respectively.[18] Step one of Staff's recommended process involves designating costs into Asset, General, or Customer categories, and is where Questions 1 through 7 of the Decision Tree are applied.[19] The outcome of Step one is that costs are categorized as Asset, Customer, or

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[18] The ACOS Whitepaper erroneously references nine questions on pages 11 and 12, and in Appendix A. There are only eight questions included in the Decision Tree methodology as shown on page 11 and described on pages 12-16 of the ACOS Whitepaper.

[19] Asset costs are associated with building and maintaining infrastructure to deliver electricity to customers, such as meters. Customer costs are those costs related with connecting and serving the customer, such as billing. General costs are related to activities that support all utility services, such as pensions, executive compensation, and general taxes.

General, and Asset costs are further allocated between the Customer, Shared, and Local cost categories.

Question 1 of the Decision Tree (i.e., "Is the cost linked to a type of asset?") is designed to determine whether the cost in question is an Asset cost or is otherwise either a Customer or General cost (i.e., whether the cost is associated with physical plant to serve customers versus other operating expenses). If the answer to Question 1 is yes, the cost is identified as an Asset, and is further allocated between Customer, Shared, and Local cost categories in Questions 2 through 6. If the answer is no, then the cost is either a Customer or General cost and will be further distinguished as part of Question 7.

Question 2 of the Decision Tree (i.e., "Are all costs attributable to customer demand?") is designed to determine whether some or all of an Asset cost should be allocated to the customer category by testing whether the Asset costs are primarily driven by increases in the number of customers or increase in customer demand. If the answer to Question 2 is "yes," the cost is identified as entirely demand-related. If the answer to Question 2 is "no," then some or all of the cost is customer-related, and any customer-related portion of such cost should be allocated to the customer cost category with any remaining costs considered demand-related. Demand-related asset costs, fully demand-related, or the remaining demand-related portion of a partially-customer cost, are further allocated between the Shared and Local cost categories in Questions 3 through 6.

The Decision Tree provides for two paths by which a cost might be classified as entirely Local, determined by the answers to Question 3 and Question 4. Question 3 of the

Decision Tree (i.e., "Could a decrease in demand result in 'unused assets?'") is designed to determine whether a cost should be entirely Local. Question 3 tests whether the asset would become stranded if an individual customer or small group of customers' decrease in load would result in an asset being stranded. If the answer to Question 3 is "yes", then that asset must be dedicated to serving that customer or small group of customers and should thus be considered a local cost. If the answer to Question 3 is "no," then further tests are necessary to determine if the asset is dedicated to serving an individual customer's or small group of customers' load, and therefore entirely Local, or if such asset is at least partially Shared.

Question 4 of the Decision Tree (i.e., "Does an increase in system coincident peak demand increase the costs?") is designed to determine if a cost would be considered entirely Local because it is linked to individual customer non-coincident demand, or if the cost is as least partially Shared. If the answer to Question 4 is "no," that is, that costs do not increase with an increase in system peak demand, then that asset must be linked to serving individual customer demand, and therefore should be allocated entirely to the Local category. If the answer to Question 4 is "yes," then the cost is at least partially Shared, and further questions are required to determine the extent to which that cost is Shared versus Local.

Staff also notes that Questions 4 and 5 are linked, and that the order in which each question is asked is important to properly categorizing the costs. Staff states that it applied a consistent methodology throughout the Decision Tree, first determining if a cost is entirely Customer, Shared, or Local, then, if not entirely one category, whether the cost should be allocated partially to one category and partially to another.

Question 5 of the Decision Tree (i.e., "Does an increase in non-coincident peak demand increase the costs?") is designed to determine if a cost is entirely Shared, or if the cost should be partially allocated to Shared and partially allocated to Local, by testing whether an increase in non-coincident demand would increase asset costs. If the answer to Question 5 is "no," then asset costs are determined entirely based on coincident peak demand and should therefore be allocated entirely to the Shared category. If the answer to Question 5 is "yes," then individual customer non-coincident demand does play some role in driving asset costs, and therefore the cost should be divided between the Shared and Local categories.

Where costs must be split between the Shared and Local categories as a result of a "yes" answer to Question 5, Staff recommends using a predetermined factor to apportion the costs between the two categories. Specifically, Staff recommends that the portion of costs allocated to the Shared category be determined by multiplying the costs by the ratio of the coincident peak (CP) demand to the non-coincident peak (NCP) at each major voltage designation - Transmission, Primary Distribution, and Secondary Distribution – with the remainder allocated to the Local category.[20] Staff claims that the ratio of coincident peak to non-coincident peak represents overall use of the asset by customers and is a reasonable proxy for identifying use of the asset, allocating costs more toward customers that make greater use of the asset. Following

[20] This ratio is referred to as CP/NCP.

Question 5 and apportionment of any split Shared and Local costs using the predetermined factor, all asset costs will have been categorized as Customer, Shared, or Local for purposes of Standby Service. However, determining which costs to include for Buyback Service requires additional consideration.

Question 6 of the Decision Tree (i.e., "Could a kW of reverse power flow increase the costs?") follows determinations made in either Questions 3 or 4 that a cost is entirely Local, and is designed to determine whether certain costs should be excluded from recovery through Buyback Service rates by testing whether costs would increase due to reverse power flow on the asset. If the answer to Question 6 is "no," then costs do not increase with reverse power flow, and Buyback Service customers should be exempted from paying for the cost since Buyback Service deals exclusively with reverse power flow from customers to the system. If the answer to Question 6 is "yes," then the costs should indeed be recovered from Buyback Service customers. Following Question 6, all asset costs have been categorized as Customer, Shared, or Local for both Standby Service and Buyback Service. However, additional questions are needed to fully allocate General costs and any non-asset Customer costs.

Question 7 of the Decision Tree (i.e., "Does the cost apply to all cost categories?") addresses non-asset costs identified by answering "no" to Question 1. 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 (i.e., a General cost), or whether the cost applies only to the Customer category. If the answer to Question 7 is "yes," then the cost is identified as a General cost, whereas if the answer is "no," then the cost is identified as a Customer cost.

Step two of Staff's recommended ACOS Methodology is triggered once each cost element has either been identified as an Asset cost and allocated to the Customer, Shared, and Local categories; has been identified as a non-asset Customer cost and allocated to the Customer category; or, has been identified as a non-asset General cost, as part of Step one. Step two involves allocating the non-asset General costs to the Customer, Local, and Shared categories. Staff recommends that such costs should be allocated to each category in equal proportion to each cost category's share of the total non-General costs.[21] Once Step two is complete, both asset and non-asset costs have been fully allocated to the Customer, Local, and Shared categories, and total percentage of service classification revenue to be collected through charges related to each of the three categories can be computed.

Step three of Staff's recommended ACOS Methodology requires that for those service classes that are charged based on reactive power charges, revenues be netted out from the total revenue requirement to be collected from customers through the various Standby and Buyback Service charges. Staff recommends that the reactive power charge revenue offset be allocated to

[21] For example, if total non-General costs are allocated 20 percent to Customer, 50 percent to Local, and 30 percent to Shared, the General costs would similarly be allocated 20, 50, and 30 percent to Customer, Local, and Shared categories, respectively.

the three cost categories based on the total cost proportion of each category.[22]

Step four of Staff's recommended ACOS Methodology includes development of Standby and Buyback Service charges based on the Customer, Shared, and Local costs identified in the previous steps. As a threshold matter, Staff recommends that Shared costs, Local costs, and Customer costs be recovered from customers through the Daily As-Used Demand Charge, Contract Demand Charge, and Customer Charge, respectively. As part of Step four, Staff recommends that rates for these charges be developed for each service classification by dividing the applicable cost category by the relevant billing determinant. Following Step four, all relevant costs have been allocated to the Customer, Shared, and Local cost categories, and rates have been developed to recover such costs from customers through an initial Customer Charge, Daily As-Used Demand Charge, and Contract Demand Charge.

Step five applies Staff's recommendation that the updated Standby and Buyback Service Customer Charge be set at the same level as the Customer Charge of the parent service classification. Step five also returns to the final question of the Decision Tree, Question 8 (i.e., "Should the Customer Charge be set to a predetermined level and any difference in cost and revenues be re-allocated?"), to determine whether and how costs would need to be allocated into or out of the Customer cost category. Staff notes that including Question 8 in the Decision

[22] Following the previous example, if 20 percent, 50 percent, and 30 percent of total costs are allocated to the Customer, Local, and Shared categories, respectively, then 20 percent, 50 percent, and 30 percent of reactive power charge revenues would be offset from the Customer, Shared, and Local costs, respectively.

Tree provides the option for the Commission to revise its guidance regarding how the Standby and Buyback Service Customer Charges should be set in the future without having to revise the ACOS Methodology itself.

Question 8 of the Decision Tree addresses differences in the revenues related to the Customer Charge applicable to the Standby and Buyback Service parent service classification, and the Customer Charge developed in Step four. If the answer to Question 8 is "no," then the rates and charges developed in Step four are the final output of the ACOS Methodology. If the answer to Question 8 is "yes," then any difference in revenues generated by the parent service classification's Customer Charge and the initial Customer Charge identified in Step four will need to be reconciled and allocated to other cost categories, and new Daily As-Used Demand and Contract Demand Charges will have to be developed accordingly.

If a portion of Customer costs need to be reallocated, Staff recommends that any difference between the revenues related to the parent service classification Customer Charge and the revenues related to the initial Customer Charge developed in Step four should be either included in or credited to the Local category, depending on whether the Customer Charge revenues under-collect or over-collect relative to the Customer costs identified in the Decision Tree. Staff reasons that the difference should be allocated to Local category since Local is the next-most similar cost category to Customer. Staff further recommends that if credits against Local costs derived from an over-collection of Customer costs through Customer Charge revenues are enough to eliminate Local costs, then any further credits should go toward Shared costs as the second-most similar cost category to Customer. Once the difference is fully allocated to the Local and Shared cost categories, final Daily As-Used Demand and Contract Demand Charges would be developed using the updated Shared and Local costs, respectively, divided by the relevant billing determinants. The results of completing Step five and answering Question 8 result in final Standby and Buyback Service rates.

a. Comments

In their initial comments, AEEI, Borrego, the City, MGN, MI, NY-BEST, NYECC, Soltage, and the JU each express overall support for the Decision Tree methodology proposed in the ACOS Whitepaper. NineDot echoes this sentiment in its reply comments. Borrego and the City each note that the Decision Tree methodology is designed to achieve more uniform, fair, and transparent Standby and Buyback Service rates across the State based on principles of cost causation, and that application of the methodology throughout the State will eliminate much of the variation among the utilities' Standby and Buyback Service rates.

While supporting the Decision Tree methodology overall, both AEEI and NY-BEST recommend various modifications or refinements, described in greater detail below. EDF cautions that any rate design methodology based on embedded costs cannot fully reflect benefits associated with new load and states that adjustments may be required to ensure that market transformation scales up in accordance with greenhouse gas goals. EDF also suggests potential changes that may need to be considered in the lens of electric vehicle (EV) charging and other technologies.

In their initial comments, AEEI and Borrego state that inaccurate allocation of costs, especially allocating Shared costs to Local, acts as a disincentive for any technology to reduce demand, and particularly harms technologies that inject power. AEEI and Borrego each note that this impact potentially reduces the State's ability to meet its climate goals.[23] Borrego states that it agrees with the ACOS Whitepaper that the September 2019 Filings did not sufficiently meet the Commission's directive in the 2019 Standby Rate Order to apply a consistent ACOS methodology.

In its initial comments, the Joint Utilities state that they disagree with various goals of stakeholders, particularly those designed to minimize the Contract Demand Charge. The Joint Utilities state that they disagree with results-oriented proposals to decrease Contract Demand Charges as such positions are inconsistent with the Commission's recognition that Standby rates are intended to be the most theoretically pure rate designs available for aligning individual customers' contributions to system costs with the rates that such customers pay. The Joint Utilities argue that artificially reducing the Contract Demand Charge would undermine both the Commission's position on Standby rate design and reduce the accuracy of price signals and eliminate operational incentives that customers face in response to such rates.

In its reply comments, NY-BEST requests that the Commission take appropriate steps to ensure that Con Edison, O&R, and Central Hudson file compliant ACOS studies following its determinations in this Order. NY-BEST recommends the Commission establish guidance and guardrails to ensure that hypothetical edge cases are not the basis for answers to Decision Tree questions. In addition, NY-BEST recommends that the Commission direct each utility to provide the rationale for its answers to the Decision Tree by voltage, and retain the

[23] AEEI also reiterates its points regarding the consequences of inaccurate rate design in its reply comments.

right to require the utilities to revise their compliance ACOS filings following this Order if the utilities file studies which diverge significantly from the Decision Tree methodology and those used by other utilities. NY-BEST asserts that this will ensure that the utilities' ACOS results are sufficiently transparent, and notes that several of the utilities answers to Decision Tree questions have already proven surprising.

In reply comments, NECHPI states that inaccurately assigning Shared costs to the Local cost category will have the effect of removing price signals from the Contract Demand Charge since the actions of a single customer would have little impact on the aggregate demand of multiple customers. NY-BEST takes issue with the JU's assertion that commenters seek merely to reduce the allocation of costs to Local to advance its own interests. NY-BEST notes that the same could be said of the JU advancing its interest in maximizing the revenue obtained through Contract Demand Charges.

In their reply comments, the Joint Utilities assert that in this proceeding the Commission must determine whether the adoption of the recommendations in the Whitepaper would result in just and reasonable rates for all customers, not just the subset of customers subject to Standby and Buyback Service rates. The JU argue that the Decision Tree Methodology proposed in the ACOS Whitepaper would result in Local cost allocations of zero for most of the National Grid, NYSEG, and RG&E customer classes, that such recommendations would eliminate or substantially minimize the Local cost allocations of other customer classes, and that the results would be similar if applied to Con Edison, Central Hudson, and O&R. The JU argue that these outcomes would result in a shift of nearly all of a Standby customer's delivery costs to other customers, and that such outcomes are unreasonable and unjustifiably favor certain energy usage characteristics over others. Responding to AEEI's assertion that Contract Demand Charges that are set above the levels determined based on cost causation principles will undercut New York's ability to reach its clean energy goals, the JU argue that the Commission should maintain its longstanding principle that rate design should be technology neutral even if stakeholders are unsatisfied with this proceeding's outcome if it fails to produce rates that provide as strong an economic incentive as they desire for clean energy resources.

In their August 23 Comments, NYECC/MTA note that well-designed cost-based rates can help provide price signals to customers to manage their load profiles to reduce their overall costs, and that all customers would share in that benefit due to a reduced need to continue to build underutilized infrastructure to meet growing peak demands. NYECC/MTA caution, however, that there is a "risk versus reward" aspect to offering optional rates to all customers and the Commission should ensure that development of such rates does not intentionally pick winners and losers. NYECC/MTA suggest that the ACOS model and Decision Tree should be periodically reexamined either as part of utility rate proceedings or as frequently as annually.

In their August 23 comments, the JU posit that well designed rates would strike a balance between cost-causation, customer orientation, and economic sustainability, and that cost-based rates benefit customers by encouraging efficient actions, investments, and use of the electric system to lower long-run costs for all customers. The JU cautions, however, that the ACOS Whitepaper recommendations, and stakeholder-recommended modifications thereto, likely resulting in minimal Local cost allocations for some of the utilities' customer classes are unreasonable because these outcomes shift delivery costs incurred on behalf of certain standby customers to all other customers.

In their September 2021 comments, the JU address stakeholder requests that the Commission accept the ACOS Whitepaper proposals and reject the JU recommendations due to the substantial record supporting the ACOS Whitepaper. The JU urge the Commission to make decisions based on the merits of the arguments contained in the comments, and not based on the headcount of stakeholder positions. In their September 2021 comments, the Sur-reply Parties contend that not only were stakeholder comments opposing the JU AAM Proposal numerous but also compelling in their merits.

b. Determination

As stated in the 2019 Standby Rate Order, the Commission's goal in requiring ACOS studies was "to produce a relatively consistent approach [to categorizing costs as Customer, Shared and Local] across utilities."[24] As a threshold matter, the Commission agrees with both Staff and Borrego that the ACOS studies submitted as part of the September 2019 Filings are not satisfactory. The Commission agrees with Staff's recommendation that an alternate methodology from those proposed by the utilities that is consistent and standardized is needed.

The Commission reaffirms that the purpose of the ACOS study is to categorize costs most accurately between Customer, Shared, and Local categories. Using the results of the ACOS study, the Commission seeks to achieve the most accurate Standby and Buyback Service rate designs possible. The Commission reaffirms that the ACOS studies and subsequent rates are to be

[24] 2019 Standby Rate Order, p. 28.

designed to be technology neutral and revenue neutral relative to the otherwise applicable service classification revenue requirements. With the Commission's prior determination to require Standby Service rates available to customers as an optional rate, it is our intent that all customers will have access to these rates as alternatives to their traditional rates, as applicable.

The Commission finds that the Decision Tree methodology, with certain modifications discussed below, will adequately produce a consistent approach to categorizing costs as Customer, Shared, and Local across utilities. The Decision Tree methodology, in general, has garnered broad support from a wide range of stakeholders. The Commission agrees with Borrego and the City that the Decision Tree's focus on achieving more uniform, fair, and transparent Standby and Buyback Service rates across the State based on principles of cost causation is meritorious, and that application of such methodology throughout the State will produce utility Standby and Buyback Service rates which are well justified and developed with a consistent approach.

The Commission's desire to implement a standardized approach also extends to our consideration of the ACOS Whitepaper's proposal to set the Standby and Buyback Service Customer charge at the same level as the Customer charge for the otherwise applicable parent service classification. The level at which the customer charge should be set for mass market customers is often one of the most contentious rate design issues in utility rate proceedings, such that the customer charge is typically negotiated and is set below the level required to fully recover the customer costs identified in a cost of service study.[25] The ACOS Whitepaper's recommendation to set the Standby and Buyback Service Customer charges to the same level as the otherwise applicable parent service classifications is reasonable as it will establish a consistent methodology for setting such charges statewide, even if the specific methodologies for developing Customer charges differ from utility to utility. Therefore, the Commission approves the ACOS Whitepaper's proposal that all Standby and Buyback Service Customer charges shall be set to the same Customer charge amount as is set for the parent service classification.

While the inputs and results of the ACOS studies should be updated as part of utility rate proceedings, desired methodological changes to ACOS studies or the Decision Tree methodology should be brought before the Commission on a statewide basis. Examining desired methodological changes outside of individual utility rate proceedings will ensure that utility-specific considerations which might be reasonable are carefully considered in a statewide context. This process will also ensure that any methodological divergences which may emerge between utilities are developed are a result of careful study of the statewide implications of such a divergence and not simply because implementing changes in an individual utility rate proceeding is expedient.

2. JU Alternate Allocation Methodology (AAM)

At the Third Technical Conference, the JU presented their proposal to implement an AAM for apportioning costs between the Shared and Local categories (JU AAM Proposal). On July 29, 2021, the JU filed a letter and supporting workpapers more fully describing their AAM Proposal. The JU note that the

[25] 2019 Standby Rate Order, pp. 16 and 62.

utilities and other parties have each interpreted the ACOS Whitepaper's Decision Tree differently and made various recommendations to modify such methodology. While the JU state that they do not waive their previous positions regarding the ACOS Whitepaper, the JU state that the intent of their AAM Proposal is to attempt to find an approach and analytical method which is acceptable to stakeholders and can be readily and consistently implemented in utility rate proceedings.

The JU state that the AAM Proposal would be implemented within the Decision Tree framework proposed in the ACOS Whitepaper. However, under the AAM Proposal, Decision Tree questions would only be answered at the customer connection voltage level, with upstream assets considered fully Shared. For each of the costs at the customer connection voltage level, the AAM Proposal would answer Decision Tree Questions 3 through 5 in a predetermined manner, answering "no" to Question 3, "yes" to Question 4, and "yes" to Question 5 such that all asset-based demand-driven costs are apportioned between the Shared and Local categories using an allocation factor. The JU state that the allocator used to apportion costs between Shared and Local would be developed separately for each service class and voltage level. The JU propose to set the Local portion of costs using the ratio of the utility's demand measure used to allocate demand-related costs at the customer connection level from its Embedded Cost of Service (ECOS) study to the individual customer maximum demands (ICMD) (AAM Allocator).[26]

As an example, the JU explain that Con Edison uses a blend of NCP and ICMD to allocate demand-related costs for

[26] This differs slightly compared to the ACOS Whitepaper's proposed allocation factor, which set the Shared portion of mixed costs based on the CP/NCP ratio.

secondary voltage customers and uses NCP to allocate demand related costs for primary voltage customers. Therefore, Con Edison would allocate secondary voltage costs to the Local category based on the ratio of blended NCP and ICMD to ICMD, and would allocate primary voltage costs to the Local category based on the ratio of NCP to ICMD. In their July 29 workpapers, the utilities demonstrate that Con Edison and O&R are the only two utilities which allocate secondary voltage demand-related costs using a blend of NCP and ICMD in their ECOS studies, whereas each of the other utilities ECOS studies allocate demand-related costs using NCP for all voltage levels.

a. Comments

In their August 23 comments, AEEI, the City, MI, NECHPI, NineDot, NY-BEST, NYECC/MTA, and UIU each request that the Commission reject the JU AAM Proposal.[27] AEEI, the City, and NECHPI each argue that the AAM Proposal fails to live up to the main goal of this proceeding to establish a methodology for designing Standby and Buyback Service rates which align as closely as possible with the real impacts of customer usage on system costs. AEEI, the City, NECHPI, and NY-BEST express concern that the AAM Proposal requires that all relevant costs go through a predetermined path of the Decision Tree with no attempt to provide a rationale for how such path would better align with actual use of the system. AEEI, NECHPI, NY-BEST, and NYECC/MTA argue that this would predetermine the outcome of the ACOS methodology through negotiation in this proceeding,

[27] Comments submitted by stakeholders related to the AAM Proposal’s impact on consistency and uniformity of ACOS methodologies among utilities, comments related to the granularity the AAM Proposal, and comments related to the AAM Allocator are addressed in separate sections by topic, below.

resulting in a different form of opaque negotiated rates after three years of effort to move away from such process.

NYECC/MTA further argue that opaque allocation of costs between Shared and Local Charges are the root of customer complaints going back decades, and that the JU's AAM proposal would result in outcomes that are not objectively arrived at, but rather in predetermined compromise positions which would render the Decision Tree useless as an analytical tool. The City and NECHPI observe that the AAM Proposal would eliminate virtually all nuance in the Decision Tree by answering Questions 3 through 5 the same way for all assets at the relevant connection voltage level. NECHPI and NY-BEST express concern that the JU's AAM proposal would entirely remove Question 6 from consideration, precluding the possibility of certain local costs being excluded from Buyback Service Contract Demand Charges since Question 6 is only answered following either a "yes" answer to Question 3 or a "no" answer to Question 4.

MI, NineDot, and NY-BEST contend that the AAM Proposal disrupts the orderly conduct of this Commission proceeding, while NY-BEST and NYECC/MTA each also question the intent of the JU's AAM proposal. MI, NineDot, and NY-BEST state that stakeholders were not afforded sufficient time to react to the JU AAM Proposal's significantly different approach and resolution compared to the ACOS Whitepaper. MI notes that the JU's AAM Proposal is complicated and was made very late into an already long-running proceeding, while also providing little to support further process and delays. NY-BEST contends that the JU's AAM Proposal, having been submitted three months after the final rounds of comments and five months after the third Technical Conference, and proposing such a drastically different proposal to the ACOS Whitepaper, conflicts with the Commission's objectives of promoting fair, orderly, and efficient proceedings. NY-BEST and NYECC/MTA suggest that the JU AAM Proposal is not driven by the development of a superior method, but by the JU's concern that the ACOS Whitepaper's results reduce Contract Demand Charges to near zero for high tension (i.e., primary voltage) customers. NY-BEST alleges that the AAM Proposal constitutes a last-ditch effort to offer a stipulated settlement position on the apparent basis of Con Edison's concern that Contract Demand Charges would be set too low for high tension customers. NYECC/MTA assert that the JU's AAM Proposal appears to discriminate against high tension customers, since the AAM Proposal appears to be solely aimed at altering the Contract Demand Charges, which such customers would pay under the ACOS Whitepaper recommendations to instead attain a particular predetermined outcome for a particular set of customers. NYECC/MTA contend that the level of Contract Demand Charges should not be a concern at all if the proportion of Shared and Local costs are determined objectively and analytically.

The City argues that although the JU allege that their proposed AAM is intended to be responsive to stakeholder concerns, the use of ICMD within such allocation is not responsive to stakeholder feedback. The City notes that the JU's recommended allocation factors based on ICMD results in a considerable shift of costs from the Shared category to the Local category, when compared to using the ACOS Whitepaper's proposed factor, yielding results that are a significant departure from the Whitepaper's proposals and the positions raised by other stakeholders. Similarly, MI, NY-BEST, and NYECC/MTA each express concern that the JU AAM Proposal provides results contrary to the results of the ACOS Whitepaper. MI argues that whereas the lower Contract Demand Charges resulting from the Whitepaper methodology are an implicit admission that the current Contract Demand Charges are too high and should be reduced, the JU AAM Proposal would result in material increases to existing Standby Service customers. NY-BEST observes that while the JU characterize their proposal as seeking to address the concerns of non-utility stakeholders by providing a reduction in allocation of Local costs from the current levels for many customer classes, the JU's AAM Proposal would, in fact, raise Contract Demand Charges for customers most likely to install larger energy storage systems at Primary voltage levels.

Similar to the concerns raise by the City, NY-BEST, and NYECC/MTA's that the AAM Proposal would increase some Contract Demand Charges from their current levels, MI argues that the AAM Proposal results in unacceptable rate impacts to existing customers. MI states that the JU's AAM Proposal would result in higher bills for 17 of NYSEG's 28 existing Standby Service customers, with 10 of those 17 customers anticipated to pay more than 10 percent more than the existing Standby Service rates, and eight of those ten with bill impacts approaching or exceeding 40 percent; 16 of National Grid's 34 existing Standby Service customers would pay higher bills under the JU's AMM Proposal, with seven of those 16 customers paying more than 10 percent higher bills, and four of those seven experiencing bill impacts in excess of 20 percent; and, four of the 21 existing RG&E Standby Service customers would experience bill increases, three of those four customers would experience bill increases exceeding 30 percent. MI asserts that there is little an existing Standby Service customer can do in response to either the ACOS Whitepaper or JU's proposed changes in methodology, and argues that bill increases of such magnitude on existing Standby

Service customers are unacceptable and contrary to the public interest and there are other rate pressures increasing certain customer bills, including the impacts of the COVID-19 pandemic, climate and energy policy initiatives, and various then-ongoing rate proceedings.

AEEI and NYECC/MTA both identify an issue with Con Edison’s July 29 workpapers, noting that Con Edison’s Customer Charge in its workpapers is set to the incorrect level, fully recovering Customer costs instead of setting such charges at the current levels. If this modification was intentional, AEEI and NYECC/MTA recommend that the Commission reject this portion of the AAM Proposal. NYECC/MTA alleges that Con Edison may be attempting to increase its fixed aggregate Customer Charge to compensate for the reduction in Contract Demand Charge revenues. AEEI notes that customer charges are typically set through negotiation at a level different than what a utility ECOS study suggests, in part because stakeholders often do not agree with the methodologies used to determine customer costs in utility ECOS studies. For example, according to AEEI, stakeholders do not agree with Con Edison’s minimum system methodology. AEEI observes that this change was not identified in the JU’s narrative explaining the AAM proposal, and that this proceeding is not the proper venue for the Commission to fully consider or adopt Con Edison’s minimum system methodology.

AEEI recommends that the Commission consider two recommendations included in the JU AAM Proposal for adoption. First, AEEI requests that the Commission approve the JU AAM Proposal’s treatment of system costs at higher voltage than the level that a customer class is interconnected to (i.e., that higher voltage-level costs above the level that a customer class is interconnected to be considered fully Shared). AEEI argues that treating these higher voltage level costs as fully Shared is reflective of real-world electric grid design. As an example, AEEI posits that while a utility may install dedicated primary voltage lines for large primary voltage customers, it is improbable that any substation or primary voltage equipment would be deployed to serve a specific secondary voltage customer, and that if such a scenario were ever to arise, such secondary voltage customer would likely be required to pay excess distribution facilities charges which would not be considered part of base rate cost recovery.

Second, AEEI notes that the AAM Proposal results in an improvement in classifying secondary voltage distribution costs compared to the utilities' March 2021 workpapers, but recommends that the Commission not sacrifice the Decision Tree by approving the AAM Proposal. AEEI notes that in the JU's March 2021 workpapers, several utilities allocated their entire secondary voltage distribution network costs to the Local category, despite that in either a Network or a Radial utility system these secondary facilities would be physically mixed between Shared and Local costs. AEEI, however, asserts that while it makes sense that secondary voltage costs would be mixed between Shared and Local, the JU's AAM proposal would answer Decision Tree Questions 3 through 5 in a predetermined manner to result in all secondary system costs being apportioned between Shared and Local using the allocation factor, obviating the Decision Tree by basing the outcome on a predetermined path that requires no decisions at all. AEEI states that the ACOS methodology employed be based on a sound rationale for answering Decision Tree questions, rather than simply agreeing to specific outcomes in advance for the sake of expedience.

In their August 23 comments, the JU defend their AAM Proposal. The JU argue explicitly that the ACOS Whitepaper Decision Tree Methodology and stakeholder-recommended modifications to such methodology would result in unreasonable rates, and implicitly that the higher Contract Demand Charges calculated using the JU's AAM Proposal are reasonable. Since the AAM Proposal builds on the cost allocation factors included in utility ECOS studies, and the utilities' ECOS studies are established in utility rate proceedings, the JU conclude that the AAM proposal can be easily and transparently integrated into the Decision Tree framework and can be established in utility rate proceedings. The JU argue that the AAM Proposal is a transparent approach to assigning costs that would be applied consistently among all of the utilities, and that although the JU have previously presented their preferred answers to Decision Tree questions, the AAM approach provides an alternative way of responding to those questions in a manner that produces results more in line with many of the stakeholders' positions.[28]

In their September comments, the Sur-reply parties point out that while only the JU support their AAM Proposal, such proposal has garnered both broad and deep opposition from diverse interest groups including municipalities, customer interest groups, and clean energy technology advocates.

b. Determination

In this section, the Commission considers the JU's AAM Proposal generally, while discussion on certain specific topics is contained in their relevant component sections below,

[28] Both Stakeholders and the JU submitted comments regarding consistency among utilities under both the ACOS Whitepaper Decision Tree and the AAM Proposal. These comments are summarized together in the relevant section below.

including the AAM Proposal's recommended Allocation Factor for splitting costs between the Shared and Local categories at Question 5, the impact of the AAM Proposal on the ability of the utilities to answer Question 6, and the methodology for setting Customer Charges. As a threshold matter, the Commission finds that the JU's AAM Proposal, while procedurally unusual, adds meaningful options for the Commission to consider with respect to the ACOS Whitepaper. Therefore, the Commission will not reject the AAM Proposal solely on procedural grounds. Although stakeholders contend that there was an insufficient amount of time to consider the recommendations within the AAM Proposal, stakeholders were afforded similar notice and opportunity to comment on the AAM Proposal as if it were a novel filing before the Commission, and the Secretary both convened a Technical Conference and solicited comments specifically on the AAM Proposal. Had the AAM Proposal been included in either the JU's initial or reply comments, it may not have been the subject of its own Technical Conference and follow-up comments. Additionally, both the JU and stakeholders availed themselves of a further round of unsolicited reply comments related to the AAM Proposal. The Commission finds that there is sufficient evidence on the record to support a decision related to the AAM Proposal.

Stakeholders assert that the JU submitted the AAM Proposal not out of a desire to implement a more powerful tool for allocating costs, but as an effort to avoid an outcome which the JU may find undesirable. Stakeholders note that the AAM Proposal sometimes results in higher Contract Demand Charges, not lower, for some types of customers when compared to current rates, and argue that the AAM Proposal results in unacceptable rate increases for some existing customers. The Commission will consider the AAM Proposal on the basis of whether it is a reasonable proposal for allocating costs to the Customer, Shared, and Local categories.

While there are certain aspects of the JU’s AAM Proposal which are meritorious, the Commission finds the AAM Proposal all together to be unreasonable for two reasons. First, the Commission agrees with AEEI, the City, NY-BEST, and NYECC/MTA that approving the JU’s AAM Proposal as a whole would be tantamount to exchanging one opaque methodology for determining Standby and Buyback Service rates for another. While the AAM Proposal does meet some of the characteristics of an ACOS study that the Commission is seeking – being more granular, repeatable, and an add-on to existing utility ECOS studies – it is lacking with respect to creating a defensible and rational method for determining the costs which should be allocated to the Customer, Shared, and Local categories and recovered through their related delivery charges.

Second, the Commission agrees with the wide array of stakeholders that the AAM Proposal to flow all demand-based asset costs through the Decision Tree along a predetermined route to Question 5, where such costs would be split between the Shared and Local categories is unreasonable. Unlike the higher voltage system costs, which are more distant from the customer and clearly shared among many customers, the lower voltage system costs more likely reflect the utility’s need to design and build infrastructure specifically to meet a single customer’s, or small group of residential customers’, maximum demand. The JU’s AAM Proposal would eliminate the option to granularly consider different infrastructure costs at the very system level where those differences would be most readily apparent.

The AAM Proposal's effect of completely bypassing the ability to consider whether it is reasonable to recover certain Local costs from Buyback Service customers is also a significant detriment to the AAM Proposal, as posed. Although the modifications the Commission is directing to Question 6 would ameliorate this situation, as discussed below, this issue nevertheless serves as a helpful illustration of why the AAM Proposal is unacceptable as it would greatly reduce the granularity intended from the Decision Tree.

While the AAM Proposal taken as a whole is unreasonable, the Commission agrees with AEEI that there are certain aspects that are worthy of separate consideration, specifically the proposal to only apply the Decision Tree on demand-based asset costs of the relevant interconnection voltage of the customer class. As discussed in greater detail in our determination below on whether to apply the Decision Tree for each combination of voltage level and service classification, stakeholders have expressed concern regarding the complexity of the ACOS study. Applying the full Decision Tree only to the most relevant voltage level, the level that the customer class is interconnected to, and making the simplifying assumption that higher voltage level costs would be shared, is both a practical improvement to simplify the ACOS study and a recognition that these costs would most likely be allocated to the Shared cost category, even using the more complex method.

While the decision to allocate higher voltage-level demand-based asset costs directly to the Shared cost category may appear to be contrary to our rationale for rejecting the overall AAM Proposal as not granular enough, this is not the case. Although the design and use of equipment installed at the same voltage level a customer is interconnected at is more likely to be designed specifically to meet a particular customer's, or group of customers', maximum demands, higher voltage level equipment is more likely installed to meet the simultaneous needs of a much greater number of customers. The perceived reduction in granularity reflects real-world electric system design, as noted by AEEI, instead of a simplistic determination to allocate costs a single way regardless of the underlying cost causation.

To be clear, only the higher than relevant customer interconnection voltage-level demand-based asset costs identified by the Decision Tree will be allocated directly to the Shared category, while other non-asset costs like General costs and non-demand costs will still be allocated using the Decision Tree, as modified herein. Implementing this change will require a modification to the Decision Tree itself. Therefore, there will be one Decision Tree which applies to all costs at the voltage level a customer class interconnects to, and a simplified Decision Tree (Higher Voltage Decision Tree) which will apply to all costs for voltage levels above that which the customer class interconnects to. This simplified Higher Voltage Decision Tree will only include Questions 1, 2, 7, 8, and 9, and is shown in Appendix B.[29] The Higher Voltage Decision Tree will allocate General costs and Customer costs in the same manner as the regular Decision Tree, but will allocate all costs to the Shared category following a "yes" answer to Question 2.

[29] The addition of Question 9 to further allocate General costs is discussed below.

3. Uniformity and Consistency Among Utilities

a. Comments

In their initial comments, AEEI, the City, NY-BEST, and NYECC each recommend that the Commission provide further clarity upfront in its determinations to help achieve consistency in the statewide approach to developing Standby and Buyback Service rates. NY-BEST requests that Commission include a memo from Staff providing additional detail and justification behind the logic of its answers to the Decision Tree questions as an appendix to this Order. NYECC states that further Commission guidance is needed to ensure that the ACOS studies remain consistent from utility to utility, and requests that the Commission eliminate as much utility discretion in answering Decision Tree questions as possible.

In their reply comments, both AEEI and the City request further Commission guidance as a means of ensuring uniformity of utility ACOS filings. AEEI states that while the Decision tree is concise, it leaves substantial room for subjective interpretation and application, pointing to differences in how the Decision Tree Questions were answered in the ACOS Whitepaper compared to how the same questions were answered by the utilities. AEEI notes that it endorses NY-BEST's initial comments in this regard. The City similarly asserts that absent Commission guidance, the utilities may be afforded too much discretion in deciding how to answer questions. As reinforcement of its argument, the City points to Con Edison's presentation at the Second Technical Conference wherein that Company indicated that it proposed to treat entire network areas as a single small group of customers, and that it intended to categorize substation costs as apportioned between Shared and Local, when, in the City's view, such costs should be categorized as entirely Shared. The City requests that the Commission provide additional guidance on application of the Decision Tree Methodology to improve consistency among utilities and decrease subjectivity.

In their reply comments, the JU address NYECC's comments expressing concern over uniformity amongst utilities. The JU state that each of the utilities answered the Decision Tree Questions in exactly the same way, arguing that the JU's answers already provide the uniformity that NYECC is seeking.

In their August 23 comments, NECHPI, NY-BEST, and UIU argue that the JU AAM Proposal lacks consistency from utility to utility. Specifically, both NECHPI and NY-BEST point to the use of different allocation factors used by Con Edison and O&R compared to other utilities for allocating secondary system costs between Shared and Local categories, arguing that these differences decrease consistency of the AAM Proposal statewide.

The JU further address stakeholder comments regarding uniformity among utilities in their August 23 comments, as they relate to both the JU's recommendations to the ACOS Whitepaper Decision Tree methodology as well as the AAM Proposal. The JU state that both the Commission and the ACOS Whitepaper seek consistency in the approach and methodology used for developing the ACOS studies, but did not intend to require complete consistency in the results themselves. The JU contend that stakeholder arguments seeking consistency among the ACOS results of different customer classes and at different utilities ignore the differences in characteristics of each utility's distribution system, and differences in the definition and usage characteristics of the utilities' customer classes. The JU contend that stakeholders' arguments regarding lack of consistency among utilities in implementing the AAM Proposal are misguided, and that the AAM Proposal can be readily and consistently implemented in utility rate cases.

In their September 2021 comments, the JU disagree with stakeholder comments alleging that the use of allocation factors among utilities is inappropriately inconsistent. The JU argue that these comments ignore that each of the JU's allocation factors for apportioning Shared and Local costs are consistent with the Commission-accepted ECOS methodologies filed in each utility's rate proceedings.

b. Determination

There are three issues to be considered in the Commission's determinations on what level of uniformity to expect from utility ACOS studies. First, stakeholders seek further guidance from the Commission in reducing the amount of utility interpretation and discretion when implementing the Decision Tree. The Commission agrees that the Decision Tree, as modified herein, is developed to be as clear as possible and minimizes the need for utility discretion and interpretation. As discussed below, the Commission is requiring various modifications to the Decision Tree methodology. For example, better defining "small groups of customers" and wording changes to Decision Tree questions should minimize the amount of remaining utility discretion and interpretation required.

Second, stakeholders request that Staff or the Commission provide further guidance on how Decision Tree questions should be answered. Stakeholders appear to be seeking upfront guidance from the Commission predetermining what the answers to Decision Tree questions should be. The Commission declines the stakeholders' request. It is the utilities that have the responsibility of filing ACOS studies and defending the reasonableness of their proposals within such studies. As the utilities and stakeholders gain experience implementing the Decision Tree, the need for further Commission guidance may arise, which the Commission will provide as appropriate.

Third, stakeholders argue that the JU's AAM Proposal is unreasonable because Con Edison and O&R use different allocation factors to apportion secondary system costs among service classifications than other utilities, while the JU contend that their AAM proposal would implement a consistent methodology statewide. While this line of comments is somewhat moot as the Commission is not approving the AAM Proposal in relevant part, it does serve to help illustrate the Commission's intent in establishing a uniform ACOS methodology. Here, the JU's argument is persuasive. The Commission seeks to implement a uniform methodology for assigning costs to the Shared, Local, and Customer cost categories, but does not anticipate that all facets of the utility ACOS studies will be uniform from utility to utility. The Commission finds that the Decision Tree, as modified herein, meets our goal of establishing a uniform ACOS methodology. Further, the Commission expects that specific non-methodological details of such studies may vary from utility to utility with relevant justification.

4. <u>Cost Account Granularity</u>

a. <u>Comments</u>

In their initial comments, the JU request they be provided the flexibility to implement the Decision Tree on either a FERC Account basis or on a Functionalized Revenue Requirement basis. The JU note that Con Edison, Central Hudson, and O&R, group FERC Account-level data into functional categories (<u>i.e.</u>, functionalized costs) that are then allocated to service classifications as part of their respective ECOS studies, and that LIPA does not file cost information on a FERC

Account basis but instead sets its rates based on a revenue requirements formula that is not directly tied to FERC accounting and includes significant non-accounting costs such as debt service. The JU state that functionalized ECOS revenue requirements can be mapped from the aggregated categories back to individual FERC Accounts, and therefore requiring the utilities that currently use the Functionalized Revenue Requirements to apply the Decision Tree at a FERC Account level would be a major undertaking only to achieve the same end results.

In their initial comments, the City and NY-BEST each request that the Commission reject the JU proposal to implement the Decision Tree using Functionalized Revenue Requirement. NY-BEST states that while a Functionalized Revenue Requirement methodology could be workable, it presents a tradeoff against uniformity of ACOS studies among utilities. NY-BEST also observes that the Functionalized Revenue Requirement method does not allow for Question 6 to be answered at all voltage levels. NY-BEST states that the purpose of Question 6 is to ensure that Buyback Service charges only reflect costs for assets that are impacted by reverse power flows, and that Buyback Service rates would be artificially inflated if they include costs unrelated to reverse power flows. NY-BEST recommends that, if the Commission allows utilities to file ACOS studies based on Functionalized Revenue Requirements, the Commission should direct Con Edison to identify asset categories which might answer "yes" to Question 6, and that Con Edison propose a method for isolating such costs from the larger category groupings. NY-BEST argues that some of Con Edison's Functionalized Revenue Requirement categories are too broad to be useful in the Decision Tree. For example, NY-BEST asserts that Con Edison's

Overhead Lines and Underground Lines costs appear to have been mischaracterized at the Secondary voltage level, as these categories of Lines - inclusive of Poles, Towers, Fixtures, and Underground Conduits - are too broad of an asset to be stranded by a decrease in demand from a specific customer. The City argues that JU did not provide enough support for their proposal.

In their reply comments, NY-BEST and AEEI provide further arguments against the use of Functionalized Revenue Requirements in the Decision Tree Methodology. AEEI argues that using Functionalized Revenue Requirement data sacrifices data granularity for no apparent benefit, while creating greater opportunities for utility judgement and subjectivity and potentially impacting the results of the ACOS study.[30] NY-BEST observes that there is a tradeoff between the granularity of data available and the ability to accurately answer Decision Tree questions, and recommends that the Commission consider how much accuracy it is willing to sacrifice to allow the downstate utilities to file ACOS results based on Functionalized Revenue Requirements.

NY-BEST further argues that although Con Edison, O&R, and Central Hudson have produced ACOS results in this proceeding based on the Decision Tree Methodology, such results do not constitute a demonstration that the results using the Functionalized Revenue Requirement basis would be the same as the results on a FERC Account basis. NY-BEST contends that the

[30] AEEI states that its recommendation does not apply to LIPA, which, as a state-owned utility, accounts for its costs differently than investor-owned utilities and has the latitude to modify the ACOS methodology implemented for its territory to suit any operational differences it may have from the investor-owned utilities.

JU cannot prove its assertions without performing a side-by-side comparison using a functionalized revenue requirement model and apply the Decision Tree on a FERC Account basis. In addition, NY-BEST argues that using the Functional Revenue Requirement basis precludes the utility from answering Decision Tree Question 6 with sufficient granularity. NY-BEST states that while the workpapers filed by Central Hudson, National Grid, NYSEG, and RG&E demonstrate sufficient granularity to answer Question 6 for relevant cost categories, Con Edison, and O&R's workpapers did not provide sufficient granularity to do so, and recommends that the Commission not accept any ACOS study which does not answer Question 6 for the relevant asset types. NY-BEST requests that if the Commission approves the use of Functionalized Revenue Requirements, it should provide additional guidance and guardrails for utilities to follow.

In their reply comments, the JU address stakeholder concerns regarding use of Functionalized Revenue Requirements. The JU argue that contrary to stakeholder positions, using Functionalized Revenue Requirements instead of applying the Decision Tree on a FERC Account basis is appropriate since the FERC Accounts can be mapped to the Functionalized Revenue Requirements, and assert that Con Edison's presentation demonstrated this at the Second Technical Conference. The JU assert that using Functionalized Revenue Requirements in ACOS studies is consistent with prior Commission direction in this proceeding, citing the description of ACOS studies in the 2019 Standby Rate Order.

Replying to NY-BEST, the JU contend that Con Edison's Functionalized Revenue Requirement has no impact on whether or not Question 6 is answered at every voltage level. The JU note that based on the way the Decision Tree is set up, it may not be possible to answer Question 6 for every voltage level, regardless of the level of granularity used in the ACOS study, since costs that flow through Question 5 are excluded when answering Question 6. The JU also state that they disagree with NY-BEST's suggestion that reverse power flows do not impact the relevant costs. The JU note that injections from batteries may, in the future, impose costs on the delivery system to accommodate novel injections of power, and that there may be injection-related costs for poles, underground conduit, and conductors depending on the magnitude of such injection.

b. Determination

There are two main issues which the Commission must consider in determining whether to allow Con Edison, O&R, and Central Hudson to file ACOS studies on a Functionalized Revenue Requirement basis, or whether to require each of those utilities to file ACOS studies on a FERC Account basis. First is the apparent tradeoff between ease of implementation for these utilities and the transparency and granularity of the ACOS study. The JU argue that because they are able to map out which functions contain costs associated with each FERC Account, the affected utilities can provide the same granularity of data without the significant effort of re-working their cost studies. The JU also argue that applying the ACOS on a Functionalized Revenue Requirement basis is consistent with past Commission precedent. NY-BEST and AEEI, however, argue that allowing the affected utilities to file their ACOS studies on a Functionalized Revenue Requirement basis sacrifices granularity, transparency, and the ability to compare costs across utilities for no apparent benefit. The JU argue that their workpapers and presentations at the Second Technical Conference demonstrate their point, while NY-BEST and AEEI contend that the JU have not supported their argument by providing a side-by-side comparison of a FERC Account-basis ACOS study and Functionalized Revenue Requirement-basis ACOS study.

Second is whether or not completing an ACOS study on a Functionalized Revenue Requirement basis provides for the ability to answer Question 6 of the Decision Tree sufficiently. NY-BEST argues that Con Edison's Functionalized Revenue Requirement-based ACOS study is insufficiently granular to answer Question 6 for all relevant asset types, particularly that some of the FERC Accounts that Con Edison functionalized and examined through the Decision Tree as a group should not have been excluded from answering Question 6. The JU counter NY-BEST by arguing that certain costs bypassing Question 6 is due to the routing of questions within the Decision Tree, not anything to do with the Functionalized Revenue Requirement basis, and that they would disagree with NY-BEST's argument that certain FERC Accounts within the functionalized groups would be excluded from recovery from Buyback Service customers even if Question 6 was not bypassed.[31]

Staff submitted the ACOS Whitepaper because there is a need for a "standard, transparent, and repeatable methodology at a comparable level of granularity" across utilities.[32] The Commission must take the utmost care in considering major foundational differences amongst utilities, such as whether some utilities are allowed to submit ACOS studies on a Functional Revenue Requirement basis instead of the more granular FERC

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[31] The ACOS and underlying ECOS studies reflect embedded (i.e., past) costs. The Commission cautions the JU not to use the possibility of unrealized, hypothetical, future injections when determining the driver of these past costs.

[32] ACOS Whitepaper, p. 9.

Account basis. The JU have demonstrated that they are capable of implementing the Decision Tree methodology on both a Functionalized Revenue Requirement basis and on a FERC Account basis. However, they have not satisfactorily demonstrated that the level of granularity between a Functionalized Revenue Requirement-based ACOS study and a FERC Account-based ACOS study are comparable. The JU's workpapers make clear which FERC accounts are included in each function, but, since a single FERC Account can be included in multiple functions, it is not clear what proportion of total FERC Account costs are included in each function.[33] Further, aggregating each of the component FERC Account costs within each function does significantly reduce the level of granularity that the Decision Tree is applied at, and requires a significant and unjustified logical leap that each of the FERC Account costs examined would vary, or not, with customer demand in the same way and thus result in the same answers to Decision Tree questions.

Regardless of whether applying the Decision Tree on a FERC Account basis results in any differences in how Decision Tree questions are answered for a particular cost, completing the ACOS study on a Functionalized Revenue Requirement-basis would result in a significant decrease in the perceived granularity and transparency of such study. There is significant value in ensuring that ACOS studies are performed in a transparent and uniform manner across utilities. Moreover, there is no apparent benefit unique to the Functionalized Revenue Requirement basis beyond ease of implementation for some utilities. The Commission finds, therefore, that it is

[33] Con Edison's workpapers, for example, show that costs related to FERC Account 364 – Poles, Towers, and Fixtures is spread over four different functions.

unreasonable to apply the Decision Tree methodology on a Functionalized Revenue Requirement basis.[34]

The Commission is concerned, however, that immediately requiring Con Edison, O&R, and Central Hudson to re-submit ACOS studies on a FERC Account basis would further impede short-term progress on improving present Standby Service rates. Therefore, the Commission finds it reasonable to accept Functionalized Revenue Requirement-based ACOS studies from these utilities for the short term only. Con Edison, O&R, and Central Hudson are directed to include an ACOS study based on application of the Decision Tree, as modified herein, on a FERC Account basis, as part of their next base rate proceedings.[35]

5. Granularity of the Decision Tree

a. Comments

In their initial comments, both AEEI and the JU argue that the Decision Tree should be applied to each customer service classification and each voltage level. AEEI states that certain questions may be answered differently if considered for each service classification and at each voltage level (i.e., between residential customers and large industrial customers). According to AEEI, the same piece of infrastructure, such as a high-tension conductor, would likely be shared if considered

[34] The Commission recognizes that as a public power authority, LIPA does not report its costs on a FERC Account basis and also includes various other cost components that are not present in typical investor-owned utility cost studies. Nevertheless, LIPA should attempt to apply its ACOS studies on a similarly granular and transparent level, if feasible.

[35] This requirement is not intended to require Con Edison to include such FERC Account-based ACOS study in its recently filed rate proceeding, Cases 22-E-0064, et al., but will require such study to be produced for its next base rate proceeding.

from a residential customer's perspective, or potentially devoted to a specific customer from a large general service customer's perspective. The JU argue that applying the Decision Tree more granularly would better reflect potential differences in customer impacts on electric system components and impacts on equipment closer to customers taking service at higher voltage levels.

The City, in its initial comments, argues that the Decision Tree should be applied once as proposed in the ACOS Whitepaper, and aggregated for all service classifications and voltages. Further, the City argues that JU did not adequately support its more granular proposal.

NY-BEST recommends, in its reply comments, that the Commission reject the JU's proposal to apply the Decision Tree separately for service classification and voltage levels at each utility and identifies four issues with applying the Decision Tree on a very granular basis. First, NY-BEST argues that applying the Decision Tree separately, as recommended by the JU, would detract from uniformity of ACOS studies among utilities since each utility has significant differences in terms of customer eligibility, primary voltage criteria, and size thresholds used to define service classifications and voltage levels. Second, NY-BEST contends that applying the Decision Tree in this way would add significant complexity to the ACOS process, resulting in utilities filing dozens of spreadsheets by service classification and voltage instead of a single spreadsheet, as contemplated in the ACOS Whitepaper. Third, NY-BEST states that allowing the utilities to apply the Decision Tree on a service classification- and voltage-specific level would allow the utilities to answer the same question differently for each service classification, even if the voltage level were the same. Finally, NY-BEST argues that allowing the Decision Tree to be applied on a service classification- and voltage-specific level provides a greater opportunity for the utilities to interpret the Decision Tree to meet their desired results, and that doing so would conflict with the uniformity, simplicity, and transparency objectives of the ACOS Whitepaper. NY-BEST adds that this level of complexity further complicates setting rates in a revenue-neutral manner. In its August 23 comments, NY-BEST recommends that the Decision Tree be applied to utility asset types by voltage level.

b. Determination

There are three contested issues regarding the granularity used to apply the Decision Tree. The first is whether or not applying the Decision Tree with increasing granularity at the voltage and/or service classification level is reasonable. Both AEEI and the JU argue that increasing granularity is meritorious because it allows the ACOS studies to consider how different customer classes and different voltage levels would contribute to grid costs differently, resulting in different allocations of Shared, Local, and Customer costs. NY-BEST, on the other hand, argues that the ability to answer Decision Tree questions differently for each voltage and service class combination is a detriment, and that allowing such would provide too much room for interpretation in search of favorable results in applying the Decision Tree. NY-BEST also argues that applying the Decision Tree on a granular basis would result in decreased uniformity among utility ACOS studies and would dramatically increase complexity of the ACOS studies.

The Commission finds AEEI and the JU’s arguments persuasive. ACOS studies are intended to be as granular as feasible, in order to match causation of the costs most accurately to the delivery charges such costs are recovered through. While NY-BEST argues against applying the Decision Tree on a granular basis since doing so could result in the same types of costs being recovered from different service classifications and voltage levels in different ways, this is in fact a desired outcome since different groups of customers interconnected to the grid at different voltages cause different costs and use the system differently. It follows, then, that the costs such disparate customer groups and usage patterns cause should be allocated differently. As discussed above, the Commission seeks a uniform methodology for performing ACOS studies and allocating costs to various service classifications, not necessarily uniform results for service classifications across utilities.

Further, although NY-BEST is concerned about significant additional complications of implementing the Decision Tree on a more granular basis, this Order directs a significant simplification to the Decision Tree methodology by applying the simplified Decision Tree for higher than interconnection voltage level costs, resulting in only the most salient costs requiring deep examination. Therefore, these two decisions (i.e., the decision to implement a simplified Decision Tree for higher than interconnection voltage level costs, and the decision to apply these Decision Trees on a FERC Account basis) in combination will make the Decision Tree both a more powerful tool for granularly designing Standby and Buyback Service rates, without overcomplicating the ACOS study process. For all of these reasons, the Commission will require the Decision Tree to be applied granularly for each combination of service classification and interconnection voltage level.

6. Definition of Local Costs

a. Comments

In the initial comments submitted by AEEI, Borrego, and NY-BEST, as well as the reply comments submitted by NECHPI, stakeholders expressed concern regarding the Whitepaper's use of a "small group of customers" when defining which costs are Local versus Shared. AEEI, Borrego, NY-BEST, and NECHPI each point to Con Edison's interpretation of "small groups of customers," which was discussed at the Second Technical Conference, as encompassing entire networks and resulting in allocating large amounts of equipment to Local. AEEI, Borrego, NY-BEST, and NECHPI recommend that the Commission clarify the definition of Local costs as those which are incurred to serve the demand of a single customer, instead of the definition used in Staff's ACOS Whitepaper, which included costs required to serve a small group of customers. NY-BEST asserts that the Commission has previously defined Local costs as those related to "a specific customer," and argues that there is nothing in the record of this proceeding to justify overturning the Commission's previously identified definition of Local costs. AEEI notes that while Staff explained in the First Technical Conference that it used the "small groups of customers" definition in considering this question for residential customers and "a single customer" in considering this question for larger commercial and industrial customers, both AEEI and NY-BEST recommend that the definition of Local costs as those undertaken to serve a single customer should also apply for residential customers. NY-BEST recommends that if the Commission decides to allow consideration of "a small group of customers" for determining residential service classification costs, the Commission should provide clear guidelines on the necessary conditions for using "a small group of customers" instead of "a specific customer." In its reply comments, NY-BEST further requests that the Commission require the utilities to apply the long-standing definition of Shared and Local costs, especially as it pertains to the longstanding definition of Local costs as those pertaining to infrastructure built to serve a single customer.

In its reply comments, the JU contend that AEEI's argument for only defining Local costs as those specific to a single customer ignores the fact that system equipment may, in fact, be installed to serve a small group of customers.

b. Determination

The JU's application of the ACOS Whitepaper's proposal to consider "small groups" of customers when answering Question 3 of the decision tree is unreasonable. While the JU's application of the proposal demonstrates that more guidance is needed on how to define "a small group of customers," the Commission finds that NY-BEST and AEEI's request to reverse the ACOS Whitepaper's proposal, and instead apply a strict definition of Local costs as those for equipment that is built to serve only a single customer, is unpersuasive. What matters for system design and cost causation is not whether multiple customers use a particular piece of equipment, but whether that equipment was sized and designed on the basis of a specific customer's maximum demand. Of particular salience for residential customers is equipment nearest to the customer, like line transformers, which must clearly be sized to meet all connected customers' simultaneous individual maximum demands, but also clearly serve more than one specific customer. This is the sort of equipment, not the entire secondary voltage system as Con Edison proposed, that should be subject to consideration of whether the costs for such facilities are Local based on a "small group" of customers.

Different utilities typically employ differently sized line transformers designed to serve a different number of residential customers.[36] The Commission must also consider the various configurations of residential customers, as some vary from single-family homes to small multi-family buildings of a handful of units, to large multifamily buildings with many individual dwellings. It is the Commission's intent to balance the need to provide a specific number to ensure that utilities do not take undue liberties with their definitions of a "small group" with flexibility such that the definition is reflective of the wide range of residential customer configurations. Therefore, a "small group of customers" shall be no greater than 10 when determining Local costs for the residential service classifications. The traditional definition of Local costs, as those required for a single customer, shall hold for all other service classifications.

7. System Architecture

a. Comments

In their initial comments, both AEEI and NY-BEST argue that Con Edison's mesh networks are different than most utility radial and loop systems, and as a result, distribution system costs much closer to customers are Shared instead of Local compared to other system architecture. AEEI requests that the Commission direct Con Edison, and any other utility that makes

[36] Staff reports that some utilities typically install one line transformer for every three single-family Residential customers, while others have varying numbers of customers, from as few as two on average to as many as nine, per line transformer, based on the size of such transformer and whether such transformer is underground or overhead.

use of networked distribution systems, to treat any network equipment that serves more than "a specific customer" as a shared cost when performing their ACOS studies. Both AEEI and NY-BEST note that Con Edison does not currently break out its network versus non-network distribution system costs. AEEI requests that Con Edison separately identify network and non-network costs, allocating network costs to the shared cost category. AEEI and NY-BEST recommend different options for separating out network versus radial equipment costs. NY-BEST recommends that Con Edison differentiate overhead assets (i.e., those assets used in radial areas) and underground assets (i.e., those assets used in network areas) by the percentage of the underground assets that belong to mesh networks. AEEI suggests that Con Edison continue its current categorization of costs, mixed between network and non-network, and allocate such costs between local and shared using Question 5 of the Decision Tree and Staff's proposed coincident peak to non-coincident peak allocation ratio.

In its initial comments, the JU disagree with NY-BEST's position at the Second Technical Conference that the Decision Tree methodology should apply to network systems differently than radial systems. The JU state that while there are differences in design, cost, and reliability between network and radial systems, the answers to Decision Tree questions, particularly Questions 3 through 5, would be the same for both network and radial systems. As an example, the JU posit that in a network area, decreases in demand can result in a reduced number of required transformers and primary cable sections.

In its reply comments, AEEI takes issue with the JU's statement that radial and network systems would produce the same Decision Tree results. AEEI contends that, on one hand the JU admit that there are differences in the design, cost, and reliability of network and radial systems, while on the other hand they ignore that such differences exist because customer load is carried in a different manner over the two types of system. AEEI argues that because load in a network system is able to flow to customers through multiple pathways, network facilities are fundamentally deployed to serve multiple customers, not just the load of any specific customer.

In its reply comments, the JU provide additional support for their position that while there are differences in design, cost, and reliability between network and radial systems, the utilities' answers to the Decision Tree Questions would remain the same whether considering a network or radial system costs. The JU note that an individual customer's load impacts various network system distribution functions just as it would a radial system. The JU argue that although decreases in an individual customer's demand would have a more obvious impact on a radial system, reductions in customer demand can result in unused assets in a network system as well. For example, reductions in customer demand can reduce prioritization for open mains replacement projects serving lower demand.[37]

b. Determination

There are two opposing philosophies at issue with respect to how the Decision Tree applies to utilities with both significant mesh network system costs and radial system costs. On the one hand, AEEI and NY-BEST each argue that there are

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[37] An open main refers to a secondary voltage distribution cable which has failed due to physical damage to the cable insulation. The JU explains that Con Edison analyzes and prioritizes open mains replacement projects and following a reduction in demand assigns a lower priority to the affected open mains.

significant differences in utility cost causation between mesh networks and radial networks, and that mesh network costs are shared much closer to the customer compared to radial systems. AEEI observes that because there are multiple pathways that electricity can flow to a customer on a mesh network, they must be fundamentally built to serve more than one customer. AEEI and NY-BEST recommend that Con Edison separately identify network and radial costs. On the other hand, while the JU agree that there are differences in design, cost, and reliability between radial and network systems, they argue that Decision Tree questions would be answered the same for both network and radial system costs. The JU also argue that decreases in customer demand can reduce the need for, or reordering of, utility infrastructure projects or programs, such as the open mains replacement program, which could constitute "unused assets" for the purpose of determining the answer to Question 3.

Both stakeholder and JU arguments rely on examining the point at which one or the other type of system architecture is built to serve more than one customer, which is addressed above in the determination regarding the Definition of Local Costs. While there may be differences in how mesh network or radial systems are designed, the Commission finds no compelling evidence that the Decision Tree needs to be applied separately to radial versus mesh network system costs. As discussed elsewhere in this Order, the characteristics of the typical usage of a piece of equipment should dictate the answers to the Decision Tree questions, which will then result in allocating the cost to the appropriate cost category, instead of predetermining whether a cost should be Shared or Local based solely on the system architecture.

There are other practical considerations which make differential application of the Decision Tree to network versus radial costs unreasonable. First, the utilities do not currently separately track network costs versus radial costs, and the FERC Accounts that costs are recorded in are not sufficiently granular to track such differences. Requiring the utilities to separately track these costs amounts to a complete redesign of utility ECOS study methodologies, which was not the intent of the ACOS study. Further, while both AEEI and NY-BEST offer proposals on how to disaggregate network versus non-network costs, neither of these proposals is sufficiently detailed or justified for Commission approval.[38] Therefore, NY-BEST and AEEI's proposals to separately identify network versus radial costs are rejected.

The JU's argument, however, regarding decreases in customer load resulting in a reduction or reprioritization of projects within the open mains replacement program requires additional discussion. The JU's assertion that it would consider such reductions or reprioritization as creating an "unused asset" is unreasonable. If an open mains replacement project is reprioritized, the need for completing such project is not eliminated, and therefore would not be considered an unused or stranded asset. Such asset should only be considered unused when a reduction in customer demand allows the open main to be permanently retired without the need for a replacement.

[38] NY-BEST's proposal assumes that all overhead assets are used solely in the portions of Con Edison's system which are radial, and that all underground assets are used solely by the portions of Con Edison's system which are networked. AEEI's proposal would bypass much of the Decision Tree and simply allocate costs between Shared and Local at Question 5, in a similar fashion as the JU's AAM Proposal.

The JU's rationale regarding reduced need for transformers is similarly unconvincing, as the JU appear to conflate customer demand reductions resulting in the need for less infrastructure in the future with the embedded (i.e., past) costs considered in the ECOS and ACOS studies.

8. Decision Tree Question 2.5

a. Comments

In AEEI and NY-BEST's initial comments, and NECHPI's reply comments, stakeholders argue that a new question should be added to the Decision Tree between questions two and three (Question 2.5), intended to determine if a cost would be allocated to shared or local if that cost category would be reduced as a result of customer injections of power. Both AEEI and NY-BEST contend that adding Question 2.5 is required to reflect the directive in the 2019 Standby Rate Order, which states, in relevant part, that "any category of costs that has the potential to be reduced by an injection should not be classified as local."[39] AEEI and NY-BEST recommend that Question 2.5 read, "would an injection of power from a customer have the potential to reduce costs?" AEEI separately posits that if a power injection can reduce load on a distribution facility, the distribution facility must be serving the load of other customers as well. As a result, a power injection has no potential to reduce costs if there is no other load on the facility for the power injection to offset. Therefore, NY-BEST and AEEI state that if the answer to Question 2.5 is "yes," the cost category would be allocated 100 percent to the Shared Costs category, whereas if the answer is "no," then the cost would continue through the Decision Tree to Question 3.

[39] 2019 Standby Rate Order, p. 28.

In their initial comments, the JU disagree that adding Question 2.5 is necessary. The JU contend that Commission language in the 2019 Standby Rate Order, which recognized that if a cost could be reduced by an injection of power, then such cost should not be considered Local, should not be taken as a generic determination. Instead, the JU argue that Local costs are the costs of facilities needed to support a customer's load in the absence of the customer's generation and, therefore, whether a customer can inject power does not change the underlying system requirements and related costs designed to meet the customer's needs when it is not injecting power. The JU recommend that the Commission reject AEEI and NY-BEST's proposed Question 2.5, arguing that the proposal is not based in fact, and that it would simply advance interests in minimizing the allocation of costs to the Local category. The JU reiterates these same arguments in its Reply Comments.

In its reply comments, AEEI addresses two of the JU's arguments. First, AEEI states that while the JU objected to its proposed Question 2.5 on the grounds that most Standby Service customers do not inject power and that Standby rates would be made available to customers without on-site generation as a rate option, the impact of injected power on system costs is a useful hypothetical for distinguishing between Shared and Local costs. AEEI argues that Question 2.5 poses a hypothetical to help determine whether a cost should be allocated to the Shared or Local category by considering whether a hypothetical injection would decrease costs, regardless of whether such injections are likely, and notes that considering the effect of power injections is useful to distinguish between Shared and Local costs because injections have an opposite effect on Shared and Local costs (<u>i.e.</u>, an injection may increase Local costs while decreasing Shared costs, whereas an equivalent consumption from the grid would increase both Shared and Local costs). AEEI contends that the Commission has previously acknowledged the probative value of considering injections to distinguish between Shared and Local costs in the 2019 Standby Rate Order. Second, AEEI argues that the JU misstates the purpose of Local costs in its assertion that Local costs are costs of the facilities needed to support a customer's load in the absence of the customer's generation. AEEI argues that it is Standby rates in total, not just the Local costs, which reflect the cost to support a customer's load in the absence of a customer's generation.

b. Determination

The Commission declines to modify the Decision Tree by adding Question 2.5, as requested by AEEI and NY-BEST. AEEI and NY-BEST's request hinges on language from the 2019 Standby Rate Order which states that "any category of costs that has the potential to be reduced by an injection should not be classified as local." In effect, NY-BEST and AEEI request the addition of Question 2.5 as another pathway to identify Shared costs, instead of its original purpose to exclude certain costs from recovery in Local charges. As correctly noted by the JU, AEEI and NY-BEST's request stretches the language in the 2019 Standby Rate Order to apply more broadly than was intended. Instead, the Commission's purpose in the 2019 Standby Rate Order language is accomplished through Question 6, as modified herein, which excludes any costs allocated to the Local category which are either unaffected or reduced by an injection of power from recovery from Buyback Service customers – customers that, by definition, inject energy into the grid.

9. Decision Tree Question 3

a. Comments

In their comments, various stakeholders requested several modifications or clarifications to Question 3. First, AEEI, NY-BEST, and NECHPI recommend, in their reply comments, replacing the "could" in Question 3 to read, "would a decrease in demand result in 'unused assets'?" Second, NY-BEST recommends that the word "entirely" needs to be added to Question 3 since nearly all assets are partially unused a portion of the time, and therefore, if an asset is entirely unused due to the disappearance of a single customer's load, then such asset would become a stranded investment and should be allocated to the Local category. Finally, AEEI recommends that Question 3 should be answered based on the typical uses of the costs in question, instead of as a search for outliers where the question could be answered in the affirmative for unusual cases.

In its reply comments, the JU contends that NY-BEST's request to add "entirely" to Question 3 ignores instances where a decrease in load by a customer or small group of customers results in a stranded asset and should therefore be considered a Local cost.

b. Determination

There are several points in Question 3 which additional guidance and clarification would be helpful. Stakeholders' request to replace "could" with "would" and AEEI's request that Question 3 be answered based on typical use of equipment both seek to eliminate as much judgement and interpretation as possible from utility answers to this question. The Commission agrees and finds that all Decision Tree questions should be answered based on typical usage of the costs in question. Unique or unusual use cases should not be the primary driver for how broad categories of costs are allocated.

The Commission also agrees with NY-BEST's rationale for adding the word "entirely" to Question 3. Where feasible, the Decision Tree itself should seek to minimize the need for utility judgement and interpretation. The purpose of Question 3 is to determine if a cost would be stranded as a result of a decrease in customer load. However, a cost cannot be truly stranded unless the need for that piece of equipment is entirely eliminated. Therefore, Question 3 shall be modified to read: "Would a decrease in demand result in an entirely unused asset?"

10. Decision Tree Question 4

a. Comments

In their initial comments, stakeholders requested two modifications or clarifications to Question 4. First, AEEI and NY-BEST, in their initial comments, and NECHPI in its reply comments, recommend that Question 4 be modified to consider all forms of coincident demand when determining if a cost is Local or Shared. AEEI notes that there are other significant and cost-relevant coincident demands than just the overall-system coincident demand, the coincident demand of a customer class, or area within the distribution system. As evidence of the importance of non-coincident peaks in driving distribution system costs, both AEEI and NY-BEST point to Con Edison's Commercial System Relief Program (CSRP) load relief zones, only some of which are coincident with Con Edison's system-wide peak, while AEEI also points to Con Edison's Rider Q Standby Rate design Pilot, which has Daily As-Used Demand Charges which have varying super-peak periods depending on which Network a customer is located in. AEEI, NY-BEST, and NECHPI recommend that Question 4 be modified to read, "does an increase in any form of coincident demand, including demand coincident with system or locational peaks, increase the costs?"

Second, NY-BEST recommends adding the words "specific customer" to Question 4, such that it reads "does an increase in specific customer non-coincident demand increase the costs?" NY-BEST argues that this clarification is necessary to make it clear that the question should apply to assets that serve individual customer peaks, and not non-coincident peak demands for an entire service classification.

In their initial comments, the JU note their disagreement with AEEI's proposed modifications to Question 4. The JU contend that AEEI's rationale, relying on a strict definition of Local costs as those costs undertaken to serve a single customer, instead of a group of customers, is incorrect and contrary to the ACOS Whitepaper's recommendations. The JU posit that AEEI's modifications would guarantee that most costs are classified as Shared regardless of the characteristics of the underlying equipment and costs. The JU also state that Con Edison's Rider Q Standby rate pilot should not the basis for a policy change for the allocation of Shared and Local costs for all New York State utilities, since the Rider Q program was not designed for that purpose and only has seven participants.

In its reply comments, AEEI recommends that the JU's arguments against modifying Question 4 should be rejected. AEEI reasons that if the system-coincident peak demand is the only coincident demand considered, the aggregate demands of hundreds or thousands of customers could be considered Local costs so long as such demand peaks do not coincide with the systemwide peak, resulting in facilities which serve many customers being categorized as Local costs.

In its reply comments, the JU contend that the network peaks referred to by AEEI and NY-BEST are non-coincident peaks by definition, and it is not reasonable to consider such peaks in Question 4 because non-coincident peaks are specifically addressed in Question 5. The JU request that the Commission reject AEEI and NY-BEST's arguments as an attempt to classify more costs as Shared.

b. Determination

The Commission finds the JU's request not to modify Question 4 to be persuasive. Question 4 considers only coincident peak demand by design, since Question 5 considers other non-coincident demands.

The Commission rejects NY-BEST's request to reference "individual customer" demand within Question 4. As discussed above, the Decision Tree questions will be answered on a small group of customers basis for residential service classifications, and on an individual customer basis for all other service classifications. Therefore, adding NY-BEST's proposed language is unnecessary for larger customers, and contrary to our decisions herein for residential customers.

11. Decision Tree Questions 5, 6, and 8

a. Comments

In its reply comments, NY-BEST recommends that the Commission require the utilities to answer Question 6 subsequent to answering "yes" to Question 5, to further differentiate the Local costs that are recovered through Standby rates versus Buyback rates. NY-BEST states that the Decision Tree excludes costs allocated to Local from being subject to Question 6 if such costs are apportioned between Shared and Local categories as a result of answering "yes" to Question 5.

b. Determination

NY-BEST is correct in its concern that certain paths through the Decision Tree, as proposed in the ACOS Whitepaper, could result in costs being allocated to Local, and thus recovered through the Buyback Service Contract Demand Charges, without an opportunity to examine whether those costs should be recovered from Buyback Service customers. In the ACOS Whitepaper, only costs allocated to the Local category as a result of answering “yes” to Question 3 or “no” to Question 4 are examined for whether it is reasonable to recover these costs from Buyback Service customers. However, costs can also be allocated to the Local category by answering “yes” to either Questions 5 or 8.[40]

The Commission finds that all costs allocated to the Local category should be subject to examination to determine if such cost is reasonable to recover from Buyback Service customers. As discussed above, the Commission’s prior statement in the 2019 Standby Rate Order that “any category of costs that has the potential to be reduced by an injection should not be classified as local,” is intended to apply.[41] Therefore, costs allocated to Local as a result of answering “yes” to Question 5 shall also be examined using Question 6 to determine if such costs are reasonable to recover from Buyback Service customers.

The Commission also finds that it is unreasonable to recover costs allocated to the Local category as a result of

[40] The ACOS Whitepaper’s proposed treatment of General costs would also result in costs being allocated to the Local category without being tested for whether it is reasonable to recover those costs from Buyback Service customers. As discussed below, the Commission’s required modifications to how General costs are allocated eliminates this pathway.

[41] 2019 Standby Rate Order, p. 28.

answering “yes” to Question 8 from Buyback Service customers. Buyback Service customers are, almost invariably, also Standby Service customers.[42] In an ideal setting where the Customer Charge for a given service classification is set to precisely collect the revenue requirement associated with the costs allocated to the Customer cost category, there would be no Customer costs recovered through the Contract Demand Charge. In this ideal setting, Buyback Service customers pay their fair share of Customer costs through their Standby Service monthly Customer Charge.[43] In reality, Customer Charges often do not reflect the full amount of Customer costs, and therefore some amount of Customer costs are allocated to the Local cost category and recovered through Contract Demand Charges.[44] Without modification to the Decision Tree methodology, a Buyback Service customer would most likely pay for more than its fair share of Customer costs since such customer would pay: (1) the Standby Service Customer Charge, which recovers most, but not all, of the Customer costs; (2) the Standby Service Contract Demand Charge, which recovers Local costs related to the Standby Service Contract Demand kW, plus the “spillover Customer costs” (3) the Standby Service Daily As-Used Demand Charges which recover Shared costs; and (4) the Buyback Service Contract Demand Charge, which would recover the Local costs related to

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[42] Staff reports that all current Buyback Service customers also currently take Standby Service.

[43] The Buyback Service Customer Charge is only collected from Buyback Service customers if they do not already pay the Standby Service Customer Charge.

[44] We refer to these Customer costs in excess of the revenues collected through the Customer Charge, and thus allocated to the Local cost category and recovered through the Contract Demand Charge, as “spillover Customer costs.”

the customer's Buyback Service Contract Demand kW and a double-collection of the "spillover Customer costs." Therefore, it is reasonable to ensure that the Local costs recovered from Buyback Service customers do not include these costs. The Commission's required modifications to the Decision Tree related to recovery of certain Local costs from Buyback Service customers are reflected in the Updated Decision Tree shown in Appendix B.

12. Allocator for Mixed Shared and Local Costs

a. Comments

In their initial comments, both AEEI and NY-BEST expressed support for the CP/NCP allocation factor proposed in the Whitepaper (Whitepaper Allocator) for apportioning costs that can neither be determined to be fully Shared or fully Local to the Shared category, with the remainder being categorized as Local following a "yes" answer to Question 5 of the Decision Tree. Both AEEI and NY-BEST state that the ratio of CP to NCP is a reasonable allocator to split those costs which are neither fully Shared nor fully Local.

In its initial comments, the JU claim that the ACOS Whitepaper's proposed Allocator is unsupported. The JU assert that while the Whitepaper includes a discussion on the importance of considering load diversity in identifying the use of utility assets, the ratio of CP to NCP demand does not capture the full diversity of a class of customers. The JU state that according to the United States Department of Energy's Load Research Manual, diversity is defined as the relationship between CP demand and the sum of ICMD within the class.

In lieu of the ACOS Whitepaper Allocator, the JU recommend that the Commission instead approve one of two alternate allocation factors, either an allocator using the ratio of CP to ICMD (ICMD Allocator), or otherwise adopt the proxy allocator used in Staff's workpapers based on the ratio of the average on-peak demand to average contract demand (Proxy Allocator). While the JU state that they prefer the ICMD Allocator, the JU note that contract demand is equivalent to ICMD, and that the comparison of average on-peak demand, computed as the sum of On-Peak Daily As-Used Demands, is a better reflection of diversity within a service classification than the Whitepaper Allocator.

In its initial comments, the City argues that the JU's recommended allocation factors should be rejected. The City asserts that the JU failed to adequately support why their proposed allocators are better than the Whitepaper Allocator, and notes that the JU's revised allocation factors would likely result in greater allocations of costs to the Local category.

In their reply comments, AEEI, the City, and NY-BEST each support the ACOS Whitepaper Allocator and recommend rejecting the JU's ICMD Allocator and Proxy Allocator. Regarding the ACOS Whitepaper Allocator, AEEI, the City, and NY-BEST argue that the Whitepaper Allocator is reasonable, with AEEI also noting that the Whitepaper Allocator has garnered support from a variety of stakeholders. NY-BEST asserts that NCP is the primary cost driver for lower voltage portions of the electric distribution system and that CP is the primary cost driver for higher voltage portions of the system, and therefore reasons that Staff's CP/NCP ratio is reflective of cost causation principles as it reflects the degree to which different customers use infrastructure at different levels of the system. The City requests that the Commission reject the JU's challenge to the Whitepaper Allocator, asserting that the JU did not provide sufficient substantiation for their argument that the Whitepaper's proposed allocation ratio of CP/NCP should be rejected because it does not capture the full diversity of a class of customers.

In its reply comments, AEEI provides significant discussion regarding the use of allocation factors to assign costs to the Shared and Local categories generally, and more specifically recommend that the Commission reject the JU's ICMD Allocator and instead accept the Whitepaper Allocator. AEEI notes that it has concerns regarding whether any measure of diversity of demand can accurately determine whether components of a distribution network are Shared or Local since the answer provided by a ratio of different types of demand is not affected by the actual use of components or topology of a system.[45] As an example, AEEI poses consideration of two hypothetical systems, a low-density rural network where each customer must be served by its own feeder and transformer, and a high-density urban area where each feeder and transformer serve multiple customers. Despite significant differences between its two hypothetical networks, costs would be allocated between Shared and Local in the same proportion among the two systems if the customer usage patterns in each system is the same. Although AEEI notes its concerns, it also points out that the alternative – engaging in a thorough statistical examination of specific facilities to determine the proportion of Shared and Local costs of distribution infrastructure - is impractical, and therefore concludes that using an allocator based on diversity of demand is reasonable.[46] However, AEEI cautions that the JU's proposed

[45] AEEI reiterates this concern in its August 23 comments, noting that the allocation of costs between Shared and Local using an allocation factor is only loosely related to actual makeup of Shared and Local costs on a system.

[46] AEEI reiterates this position in its August 23 comments.

ICMD Allocator is the least reasonable allocator of those presented. AEEI argues that using the ICMD as the denominator of such ratio relies on the faulty assumption that all distribution infrastructure is built to accommodate unrealistic conditions of all customers using electricity at their historical maximum levels simultaneously. AEEI notes that the design of distribution systems recognizes that customers will use power at different times, and a customer NCP, as used in the ACOS Whitepaper Allocator, is a more realistic measure of the maximum demand that individual components of the electric system are designed to accommodate.[47]

In their reply comments the City and NY-BEST also request that the Commission reject the JU's ICMD Allocator and Proxy Allocator. Echoing arguments expressed by AEEI, NY-BEST states that the JU's use of the ICMD makes the assumption that the entire system is built to handle all customers consuming their maximum demands at the same time with no diversity of load. NY-BEST states that while it agrees that infrastructure proximate to the customer must be sized to meet ICMD, the costs considered in the ACOS Methodology, even if considered on a FERC Account basis, are not granular enough to isolate facilities that are specifically installed to meet the maximum demand of any specific customer. Both the City and NY-BEST argue that the JU have failed to establish that their proposed allocation ratios are more appropriate than that presented in the Whitepaper, with NY-BEST further arguing that there is little evidence to support the ratio of Average On-Peak demand to Contract Demand on the record, that such ratio has not been used elsewhere, and questioning whether each utility's Contract

[47] AEEI reiterates this position in its August 23 comments.

Demand values reflect present grid conditions. The City notes that the JU's preferred allocation ratios would have a material impact on the allocation of costs between Shared and Local categories, resulting in costs being shifted out of the Shared category and into the Local category.[48] The City states that the Whitepaper's CP/NCP allocation ratio generally results in a more appropriate allocation of costs to the Shared category, and therefore the JU's preferred allocation ratios should be rejected.

In their reply comments, the JU addresses the City's argument that that the JU failed to justify its proposed CP/ICMD ratio. The JU states that they fully addressed their position at the Second Technical Conference that the CP/ICMD ratio better reflects diversity within a customer class. The JU contends that the City's preferred ACOS Whitepaper Allocator is not well supported, alleging that such ratio was based only on a generalization that the ratio of CP to NCP is a proxy for identifying the usage of an asset.

In its August 23 comments, NY-BEST provides further support for the ACOS Whitepaper Allocator. NY-BEST states that allocation of costs to the Local category using the ACOS Whitepaper Allocator will be self-adjusting as developers construct more energy storage systems. NY-BEST explains that as the amount of energy storage on the electric grid increases, the relative amount of NCP will increase compared to the amount of CP, and, therefore, when the allocation factors are re-examined, an increasing amount of NCP compared to CP would result in a higher proportion of costs being allocated to Local instead of Shared. As an example, NY-BEST provides an example showing

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[48] The City reiterates this position in its August 23 comments.

current ratios of CP/NCP decreasing from the current mid-to upper-ninety percentiles to as low as the mid-fiftieth percentile as the amount of energy storage increases to the 2030 New York State goal level. NY-BEST contends that due to the self-adjusting nature of the Whitepaper Allocator and the small number of customers currently taking Standby Service, using the Whitepaper Allocator will not result in significant cost-shifts to customers that do not take Standby Service. NY-BEST recommends these allocators should be re-examined during utility rate proceedings, or as frequently as annually.

In their August 23 comments, the City, MI, NineDot, NY-BEST, and UIU argue that the JU's AAM Allocator lacks adequate support. The City and NY-BEST each state that the JU have failed to demonstrate why their proposed AAM proposal is consistent with the direction provided by the 2019 Standby Rate Order, or that such proposal would produce Standby and Buyback Service rates that are more reasonable than the ACOS Whitepaper's proposed allocation factor. The City argues that it is unclear that the ICMD is necessary for assessing diversity at the service class level, and have not offered an explanation or example of what costs ICMD captures that the ACOS Whitepaper Allocator does not. Similarly, NY-BEST argues that the JU has not adequately explained how their proposed AAM Allocator accurately reflects the proportion of shared and local costs required to serve customers. UIU argues that the JU did not provide evidence that the ICMD is an accepted ratemaking tool in other jurisdictions, and failed to either adequately support the use of the ICMD for statewide implementation or provide adequately standardized ECOS study procedures. UIU observes that even though the only JU member utility which currently uses ICMD as part of its ECOS study is Con Edison, the JU propose to incorporate an ICMD-based allocation factor at each of the investor-owned utilities.

In their August 23 comments, both NY-BEST and NECHPI identify problematic mathematical issues with the JU's proposed AAM Allocator. NY-BEST notes that Con Edison and O&R's proposed use of the ratio of a blend of NCP and ICMD to ICMD, mathematically places a floor on the proportion of costs that would be allocated to Local based on the NCP to ICMD blend percentage, and argues that this result seems arbitrary and has not been adequately justified.[49] NECHPI notes that while Con Edison presented that its AAM Allocator for secondary systems would be based on a blend of NCP and ICMD, the Company did not specify what the blend was.

In its September 2021 comments, the JU argue that the ACOS Whitepaper Allocator is unsupported, and that, instead, the record does support the JU's preferred allocators. The JU contend that the ACOS Whitepaper never explained why its proposed allocation factor based on the CP/NCP ratio is reasonable, and that such proposal is itself unsupported, and that although many stakeholders support the ACOS Whitepaper's proposed allocation factor, they provide no evidence of explaining why the ACOS Whitepaper Allocator is reasonable.

In their September 2021 comments, the Sur-Reply Parties argue that, contrary to the JU's position, the ACOS Whitepaper Allocator is supported, and it is the JU's allocators which are not supported. In support of the ACOS Whitepaper Allocator, the Sur-Reply Parties state that stakeholders have

[49] For instance, a 50/50 blend of NCP and ICMD would produce an allocation factor which can be no less than 50 percent Local, whereas a 75/25 blend of NCP and ICMD would produce a floor of 25 percent Local, and a 25/75 blend of NCP and ICMD would produce a floor of 75 percent Local.

provided justification and support for the ACOS Whitepaper Allocator, and the JU's position that such arguments are not compelling does not mean that the arguments are not present in the record. The Sur-Reply Parties further argue that the ACOS Whitepaper Allocator was developed specifically for the purpose of allocating costs between Shared and Local categories, and better reflects the Commission's definitions of Shared and Local costs uniformly across all utilities than any JU-recommended alternative. Arguing against the JU's proposed allocators, the Sur-Reply Parties argue that while the JU have stated that the allocation factor used to apportion mixed Shared and Local costs should reflect the greatest diversity of demand on the system, the JU have not justified their position by explaining how their preferred allocator would result in a cost allocation that better fits the Commission's definition of Shared and Local costs. While the Sur-Reply Parties admit that the JU's preferred allocation factors may be consistent with the ECOS methodologies and studies the utilities file in their rate proceedings, such ECOS methodologies do not achieve the outcomes sought by the Commission in previous Orders or in the development of an ACOS methodology. The Sur-Reply Parties further argue that the allocators used in utility ECOS studies predate the present proceeding, were not developed for the purpose of allocating costs between Local and Shared categories, that such ECOS methodologies have only been accepted as inputs to rate proceeding settlements instead of specifically approved on their own merits, and that the JU's preferred allocators' inclusion in a utility ECOS study does not provide sufficient rationale to adopt such allocators for use in an ACOS study.

b. Determination

The Commission finds the ACOS Whitepaper's proposal to allocate costs that cannot be determined to be fully Shared or fully Local using a specified Allocation Factor to be reasonable. AEEI's concerns regarding using an Allocation Factor to designate a portion of costs as Shared and the remainder as Local are valid. As illustrated in AEEI's example, use of an allocator can result in the same proportional allocation of costs among vastly different utility systems. However, no reasonable alternative to using such a factor is readily apparent. While AEEI suggests that an examination of a statistically significant sample of actual equipment would be preferable, the Commission agrees with AEEI's conclusion that such an exercise is impractical. Staff, utilities, and stakeholders attempted this very exercise following the 2001 Order directing development of Standby rates, leading to the negotiated standby matrices approved by the Commission in 2002 and 2003, which Staff, utilities, and stakeholders have spent the past seven years in this and other proceedings working to reform.[50]

[50] Case 99-E-1470, Electric Standby Service, Opinion and Order Approving Guidelines for the Design of Standby Service Rates (issued October 26, 2001); Case 01-E-1847, National Grid Standby Service Rates, Order Approving Joint Proposal (issued June 21, 2002); Case 02-E-0551, RG&E Standby Service Rates, Order Establishing Electric Standby Rates (issued July 29, 2003); Case 02-E-0779, NYSEG Standby Service Rates, Order Establishing Standby Service Rates (issued July 30, 2003); Case 02-E-0780, et al., O&R and Con Edison Standby Service Rates, Order Establishing Standby Rates (issued July 29, 2003); Case 02-E-1108, Central Hudson Standby Service Rates, Order Establishing Electric Standby Service Rates (issued December 4, 2003).

The Commission must therefore determine which of the imperfect tools at our disposal creates the best match between cost causation as a result of customer usage patterns and the way that revenues will be collected from customers though Standby rate charges. Before the Commission in this proceeding are four options. The first option is the ACOS Whitepaper's proposed CP/NCP Allocator, which has garnered broad support from stakeholders but is opposed by the JU. The second option is the JU's preferred allocator based on the ratio of CP/ICMD. The third option is the JU's proposed proxy allocator based on the ratio of average On-Peak Daily As-Used Demand to average Contract Demand, which the JU offered as an alternative to its preferred allocator. The fourth option is the JU's AAM Proposal allocator based on the ratio of whichever demand allocator is used to allocate functionalized demand-based costs in a utility's ECOS study for the relevant voltage level to the ICMD, which the JU offered as a form of "settlement position" to decrease Contract Demand Charges from their current levels, but not result in minimizing or eliminating Contract Demand Charges for customers connected at primary voltage. Each of the JU's proposed allocators, the ICMD Allocator, Proxy Allocator, and AAM Proposal Allocator are supported only by the JU and are otherwise unanimously opposed by other stakeholders.

Both the JU and stakeholders' allegations that one side or the other's proposals are not supported are not helpful in determining which Allocation Factor is best. The JU argue multiple times that the ACOS Whitepaper's CP/NCP Allocation Factor is unsupported. Several stakeholders argue that the JU has not supported its preferred alternatives. These arguments do not provide any new information to base a decision upon and are largely undermined by the fact that the ACOS Whitepaper, the

JU, and stakeholders each provide a rational basis for their proposals. However, the Commission is satisfied that there is sufficient evidence and rationale provided in this proceeding to select among one of the four proposed Allocation Factor methodologies.

As discussed above, the intent of the ACOS study and the Decision Tree methodology is to best match the rates customers pay with the causation of the costs recovered through those charges, not to either minimize Contract Demand Charges or otherwise maintain some minimum threshold amount of revenue to be collected through the rate components. Therefore, the Commission will not reject any such proposal out of hand based on lack of support or in sole consideration of the resulting rates. Instead, the Commission will select an Allocation Factor from among the submitted proposals based on the merits of the arguments submitted supporting or opposing the proposal, not based on a simple headcount of the parties supporting or opposing any particular proposal, as the JU helpfully suggest.

The Commission finds that the JU's arguments for using the ICMD Allocator, Proxy Allocator, and AAM Proposal Allocator proposals are not persuasive.[51] While ICMD-based allocators may measure the diversity of customers themselves, they don't align

[51] As discussed in greater detail below, although the Commission finds that use of an ICMD-based Allocation Factor is not ideal for the purpose of determining the Shared and Local allocations for costs that are neither fully Shared nor fully Local, this determination should not be construed as wider commentary on the use of ICMD in utility cost studies more generally. Further, UIU's opposition to the use of ICMD in utility cost studies is undermined by the Commission's acceptance of Con Edison's ICMD-based ECOS study cost allocations in the 2017 Con Edison Rate Order as a result of litigation which UIU itself instigated. See 2017 Con Edison Rate Order.

with the main purpose of the ACOS study to determine if customers use the system in a way that is broadly similar to other customers, thus contributing to shared costs, or broadly differently from other customers, thus contributing to local costs. AEEI and NY-BEST's rebuttal of the JU's preferred ICMD-based allocators is particularly salient, as basing the Shared/Local allocator on ICMD would indeed reflect the unrealistic scenario that the electric system is built to meet all customers' maximum demands simultaneously. Simply put, using an ICMD-based allocator does not reflect either customers' actual usage of the system nor the way that the system is designed. The JU's proposed proxy allocator, based on the ratio of average On-Peak Daily As-Used Demand to average Contract Demand, is, by the JU's admission, effectively the same as an ICMD-based allocator, and is therefore not appropriate for the same reasons.

NY-BEST also highlights a potentially unintended consequence of the JU's AAM Proposal Allocation Factor where ICMD would be in both the numerator and the denominator for Con Edison and O&R's secondary voltage customers, resulting in a mathematically imposed floor of the proportion of costs being assigned to Local based on the blended percentage of the numerator. This feature of the AAM Proposal produces an unreasonable result of administratively locking the potential proportion of costs allocated to Shared and Local, not by characteristics of the system or customer usage of such, but based on a predetermined blending percentage, which is itself not well justified in the context of an ACOS study. In addition, the JU puts great stock into its AAM Proposal's Allocation Factor as being consistent with the way that existing ECOS studies allocate functionalized costs to customers. As the

Sur-reply Parties note, however, those ECOS allocations were never intended or examined as a vehicle for splitting costs between the Shared and Local categories. Further, as the Sur-Reply Parties note, had these ECOS allocators been sufficient, the Commission need not have embarked on this seven-year process culminating in the instant proceeding.

The Commission finds that the ACOS Whitepaper's proposed CP/NCP Allocation Factor is reasonable. The Commission is persuaded by the Whitepaper's rationale, bolstered by comments submitted by AEEI and NY-BEST, that the CP/NCP ratio more accurately represents the cost causative manner in which customer usage impacts the grid than other Allocation Factor options. As recognized by AEEI and NY-BEST, NCP, is a more realistic driver for utility infrastructure costs than ICMD, and therefore the ACOS Whitepaper's proposed CP/NCP Allocation Factor will have a stronger basis in cost causation principles than the JU's proposed alternatives. NY-BEST's analysis showing that the Whitepaper's CP/NCP ratio will self-adjust is particularly convincing. As NY-BEST demonstrates, CP/NCP ratio will adjust over time resulting in a greater share of Local costs with increasing energy storage penetration, thus limiting the long-term potential for intra-class cost-shifts or subsidization.[52]

13. General Costs

a. Comments

In its initial comments, the JU recommend that General costs should be functionalized to the respective voltage and usage areas, and be allocated in the same manner as the other functionalized costs. As a result, each cost considered in the Decision Tree would be the sum of the actual equipment costs plus an "adder" to recover a portion of the general costs apportioned to the relevant cost function. The JU state that current ECOS studies already functionalize General costs, and that such functionalized costs should be allocated in the same manner as the other functionalized costs. As an example, the JU state that all General costs functionalized as Transmission in the ECOS study would be considered entirely Shared, consistent with the Decision Tree outcome for Transmission costs. The JU posit that this treatment of General costs would ensure consistency with the utilities' underlying ECOS allocations and allow each utility to use its ECOS study as the starting point in the ACOS Methodology.

In its initial comments, the City recommends that the Commission reject the JU's proposal to split General costs

[52] As NY-BEST notes, the CP/NCP ratio used for this purpose should be updated periodically as part of utility rate proceedings, roughly every one to three years. While the value of the CP/NCP Allocation Factor should be updated in utility rate proceedings, proposals for deeper methodological modifications to ACOS study methodologies should be brought before the Commission in a petition outside of any particular utility rate proceeding so the proposal can be examined on a statewide basis. As previously discussed, the Commission seeks to establish and maintain a single statewide ACOS study methodology to the greatest extent possible.

outside of the Decision Tree using the results of the ECOS. The City argues that the JU did not sufficiently support their proposal.

In its reply comments, the JU further argue that using the ECOS allocations of costs to functions instead of the separate treatment proposed in the Whitepaper is consistent with description of ACOS studies provided in the 2019 Standby Rate Order that the ACOS studies should build upon an existing ECOS study.

b. Determination

The Commission finds that while both the treatment of General costs proposed in the ACOS Whitepaper and by the JU contain meritorious elements, neither the ACOS Whitepaper proposal nor the JU proposal individually reach a reasonable outcome. As shown in the utilities' workpapers, in practice General costs are comprised of two primary categories: (1) administrative and general (A&G) costs, and (2) taxes other than income taxes. Con Edison and O&R each further break out these non-income taxes into Property Taxes and Payroll Taxes. For A&G costs, the JU's proposal to include these costs, based on the method each utility uses to functionalize A&G costs to the various voltage levels and usage areas essentially as adders to asset costs, misses the core tenet of the ACOS study – to assign the amount of revenue to be collected through Shared, Local, and Customer Charges as closely as possible to cost causation. Similarly, the ACOS Whitepaper proposal would allocate these A&G costs to the Shared, Local, and Customer categories based on the percentage of other non-general costs assigned to those categories. Neither the ACOS Whitepaper proposal nor the JU's recommended treatment accurately matches A&G cost recovery to the predominantly fixed nature of its cost causation.

Instead of either the ACOS Whitepaper proposal or the JU's recommended treatment, the Commission will adopt a methodology for allocating A&G costs which better matches the predominantly fixed nature of A&G costs with a cost category that is predominantly collected through fixed charges. Therefore, the Commission finds that the A&G cost portion of General costs shall be allocated to the Customer cost category.[53] This determination follows the basic principles for setting economically efficient rates that fixed costs should be recovered through fixed charges, and also recognizes that where these fixed A&G costs cannot be recovered through the fixed Customer Charge, it would instead be recovered through the next-best charge - the Contract Demand Charge.

Where A&G costs are, by definition, not related to any particular asset, and therefore do not intrinsically vary with changes in either the number of customers served or with customer demand, payroll and property taxes in particular, and the other non-income tax category more generally, are more closely linked both to assets and customer demands. Property taxes provide the most direct example – if a utility has to build a new substation to meet customer demand, it will also have to pay property tax on that substation, thus a utility's property tax costs are directly related to their asset costs, and are indirectly related to the customer demands that necessitate investing in those assets. Payroll tax is also related to asset investments and customer demands. For example, a utility will need to grow its workforce to manage a growing

[53] As with other Customer costs, any A&G costs allocated to the Customer cost category that cannot be recovered through the Customer Charge should instead be allocated to the Local cost category.

system, and may require additional workers regardless of whether it must invest in new assts to help manage customer demands through typical "blue sky" operations, emergency response, and demand management efforts such as energy efficiency, demand response, and non-wire alternative projects.

Therefore, the Commission finds the JU's recommendation reasonable to functionalize the costs related to Taxes Other than Income Tax to the various voltage levels and usage areas of each utility using the same method as it does in its ECOS study. Once functionalized, these Taxes Other than Income Tax costs would be treated as adders to the associated asset costs within each function and thus be allocated to the Shared, Local, and Customer categories in the same manner as those assets. This methodology closely matches recovery of Taxes Other than Income Tax costs to the recovery method for the associated assets, thus continuing to closely match cost recovery with cost causation.

This modification to the ACOS Whitepaper's proposed treatment of General costs requires addition of another Question to the Decision Tree. Therefore, Question 9 shall be added following Question 7, and before Question 8. Question 9 will ask, "is the cost a tax related to either a specific asset or cost which varies with customer demand?" If the answer to Question 9 is "yes," then these tax costs should be treated as adders to the associated costs, and be allocated to the Shared, Local, and Customer categories in the same manner. If the answer to Question 9 is "no," then these non-tax General costs should be allocated to the Customer cost category. An updated Decision Tree which reflects the addition of Question 9 is included in Appendix B.

Rate Design Issues

1. ECOS Study Approaches

a. Comments

AEEI in its initial statement, and NECHPI in its reply statement each recommend that the "minimum system" methodology of setting customer charges used by several utilities, notably Con Edison, should not apply to ACOS studies. Both AEEI and NECHPI note that the minimum system method allows for some costs that serve customer demand to be allocated to the customer charge, and therefore that a sizeable percentage of demand-related costs may be allocated to the customer charge before the ACOS methodology is even applied, thereby allowing utilities to bypass the Decision Tree methodology and allocate a percentage of demand-related costs to local. AEEI notes that it is not aware of any instance where the Commission has specifically endorsed the minimum system method for setting customer charges, and that most recent customer charges set in utility rate cases do not reflect the determined minimum system charge and instead reflect a different amount determined through settlement. Both AEEI and NECHPI request that the Commission require all utilities to apply the Decision Tree methodology to all demand-related costs, including those that would otherwise be allocated to the customer charge under the minimum system method, and AEEI further recommends that this should not occur until such time as the Commission has undertaken review of the minimum system methodology. In its August 23 comments, AEEI recommends that the Commission consider investigating the impact of Con Edison's minimum system methodology in ECOS studies more generally outside of this proceeding.

In its initial comments, UIU also expresses concern regarding existing utility ECOS studies. UIU highlights the lack of consistency among the investor-owned utilities in the development of ECOS studies, the output of which is utilized by the ACOS methodology, and recommends that the Commission evaluate and standardize ECOS studies on a statewide basis before considering further rate design issues, especially for mass market customers.[54]

In their reply comments, the JU state that neither of AEEI's concerns, that using the minimum system methodology will allow utilities to bypass the Decision Tree and allocate a portion of demand-related costs to the Local category, and that the Commission has never endorsed the minimum system methodology, are valid. The JU assert that the Commission directed that the ACOS methodologies are to rely on existing ECOS studies in the 2019 Standby Rate Order, a position which was also advanced by Staff at a Technical Conference following the 2019 Standby Rate Order but preceding the ACOS Whitepaper. The JU state that Con Edison has used the minimum system methodology for many years, and that the Commission has previously approved the minimum system methodology as part of the litigated phase of Con Edison's 2016 rate proceeding wherein the Commission dismissed challenges to Con Edison's minimum system methodology-based ECOS study.[55] The JU point out that the Commission specifically addressed issues related to portions of Con Edison's transformer costs being included in the Customer Charge as a result of the minimum system methodology, found such results reasonable and in line with recommendations provided in the Electric National Association of Regulatory Utility Commissioners Manual on utility cost studies, and approved Con

[54] UIU reiterates these positions in its August 23 comments.

[55] 2017 Con Edison Rate Order.

Edison's ECOS study. The JU note that although Con Edison's Customer Charge is set at a level less than that identified in its ECOS study, the resulting Customer Charge does indeed reflect the use of the minimum system methodology as a portion of the minimum system costs recovered through the current Customer Charge.

The JU allege that AEEI's concerns are little more than a results-oriented recommendation to significantly reduce the Contract Demand Charge, and that AEEI's recommendations would result in the Decision Tree inaccurately allocating certain Customer costs to the Shared category. In addition, the JU note that AEEI's argument that the minimum system methodology deserves review before the Commission implements new Standby and Buyback Service rates, based on Con Edison's ACOS results, is beyond the scope of this proceeding.

b. Determination

Although the Commission recognizes that issues with the utilities' underlying ECOS studies can have an impact on the outcome of the ACOS study and resulting Standby and Buyback Service rates, the JU is correct that issues regarding the ECOS studies are beyond the scope of this proceeding. As a threshold matter, the ACOS study was always intended to be an add-on to a utility ECOS study, as discussed in the 2019 Standby Rate Order.[56] While there may be instances where the ACOS study treats some cost elements differently than the treatment included in the ECOS study – General costs for example, as discussed above – the purpose of the ACOS studies are to best match utility costs with the charges to recover such costs with minimal disruption of the underlying ECOS study, not to

[56] 2019 Standby Rate Order, p. 27.

precipitate statewide reevaluation of ECOS study methodologies used by the utilities. Further, issues related to utilities' ECOS studies and methodologies are well-suited for consideration in utility rate proceedings. Therefore, the Commission declines to adopt AEEI and NECHPI's request that the "minimum system" methodology used in Con Edison's ECOS study not apply to ACOS studies.[57]

Similarly, the Commission need not undertake a full statewide examination of utility ECOS study methodologies and implement a single statewide methodology, as suggested by UIU, prior to considering mass market demand rate issues or Standby and Buyback Service rate issues more broadly. The methodologies for determining such rates approved herein represent a significant improvement over the previous methods, regardless of any issues with the underlying ECOS studies, and should not be delayed any more than is required to carefully consider the options before the Commission presently. Therefore, UIU's request that the Commission cease action on Standby and Buyback Service rates until after a statewide review of utility ECOS studies is rejected.

2. Revenue Impacts and Decoupling

a. Comments

In their initial comments, both the JU and AEEI were in general agreement that differences in forecast utility revenues resulting from the changes in Standby Service rate design need to be addressed. The JU note that application of

[57] Although AEEI states that it is not aware of any time the Commission has endorsed the minimum system methodology in a litigated portion of a utility rate proceeding, the JU are correct in pointing out that the Commission has indeed considered exactly such topic in its 2017 Con Edison Rate Order.

the ACOS Methodology is likely to produce new Standby rates for each utility, and such new rates will result in different revenues than those which were computed when revenue requirements for each utility were last determined. AEEI observe that large shifts in the size of Contract Demand and Daily As-Used Demand Charges could have an impact on utilities' ability to recover their pre-determined revenue requirements, especially if such changes induce greater investments in DER and other outcomes supportive of New York's energy policy goals. The JU note that while some utilities already include revenues resulting from customers participating in Standby rates in their respective Revenue Decoupling Mechanisms (RDMs), others do not.

Both AEEI and the JU recommend that the Commission implement a true-up mechanism for the affected utilities, and recommend that treatment of Standby rates in RDMs should be addressed in each utility's next rate proceeding.[58] The JU posit that changes to the Standby rates and the revenues they are designed to produce will require a true-up mechanism for those utilities that do not have an RDM for the existing service classifications that are required to take Standby Service so that the new rates do not produce either a revenue windfall or shortfall for each affected utility, while AEEI recommends that the Commission consider applying the RDM to all utilities' Standby and Buyback rates, based on revenues generated through the Daily As-Used Demand Charge.

In its initial comments, NYECC urges caution in applying RDMs to the newly developed Standby Service rates. NYECC states that it may be prudent to see how any newly adopted

[58] The JU reiterate these positions in their August 23 comments.

rates operate before prematurely applying the RDM, which may not be necessary in the near term.

In its reply comments, the JU argue that both AEEI and NYECC's comments related to implementing an RDM for Standby Service customers are moot. The JU state that the Commission has already required that customers voluntarily participating in Standby rates be included in the relevant parent service class RDM as part of the 2019 Standby Rate Order, and that some utilities already have an RDM for those customers that are billed under Standby Service on a mandatory basis. The JU concludes that the only outstanding issue related to the treatment of utility revenues is for existing Standby Service customers which are not covered by an existing RDM at some utilities.

In its reply comments, AEEI agrees with the JU's proposed true-up mechanism. AEEI notes that the purpose of the ACOS studies is to better align Shared and Local cost allocations with the design of electric distribution systems, not to create utility revenue losses or windfalls. AEEI states that the JU's proposed true-up mechanism would serve a similar function to immediately implementing RDMs, and would allow any issues related to RDMs to be considered in the context of utility rate proceedings.

b. Determination

As a threshold matter, the JU is correct that the only issue which needs to be considered with respect to the true-up of utility revenues under updated Standby and Buyback Service rates is indeed for those utilities whose Standby and Buyback customers are not presently included in an RDM.[59] The JU's proposal to implement a mechanism to true-up utility revenues to the levels established in their respective rate proceedings until RDMs for Standby and Buyback Service customers can be established in rate proceedings, has garnered stakeholder support. Establishing a true-up mechanism now allows for a more permanent solution to occur as part of individual utility rate proceedings as they come forward for Commission review.

Therefore, the affected utilities (i.e., Central Hudson, Con Edison, O&R, NYSEG, and RG&E) shall defer any differences in collected revenues from existing Standby and Buyback Service customers billed at the new rates versus revenues that would have been collected if billed under current rates, either for future recovery from customers, or for refund to customers, as applicable. These deferral balances shall accrue separately for each customer class, and shall be collected from or passed back to the same service classification the next time that base rates are reset. By separately accruing balances for each affected customer class and matching recovery or refund of those balances to the customer class in the next rate proceeding, this deferral accounting method will act similarly to an RDM for those utilities that do not currently include Standby and/or Buyback Service customers within an existing RDM. In addition, the affected utilities are directed

[59] National Grid includes both Standby and Buyback Service customers in their parent service classifications' RDM targets, whereas Central Hudson includes only Standby Service customers in their parent service classification's RDM. Con Edison, O&R, NYSEG, and RG&E each typically exclude both Standby and Buyback Service customers from RDM targets, except where a customer is exempt from paying Standby rates and where customers are participating in Standby rates as an optional demand rate per the 2019 Standby Rate Order.

to include a proposal in their next rate proceeding on whether and how to include Standby and Buyback Service customers in an RDM.

3. Impacts on the Reliability Credit

a. Comments

In their initial comments, both MI and NYECC state that Reliability Credits are a means of rewarding customers who reliably reduce load below the contract demand during the summer period and should be maintained. Both MI and NYECC express concern that new Standby rates established using the ACOS methodology, which either reduce or eliminate Contract Demand Charges by shifting costs previously recovered through the Contract Demand Charge into the Daily As-Used Demand Charges, may eliminate or reduce those credits for certain customers and undermine the intent of the Reliability Credit. MI argues that an alternative approach is needed to preserve the value of the Reliability Credit, such as applying the Reliability Credit based on avoidance of Super-Peak Daily As-Used Demand Charges.

In their reply comments the JU disagree with NYECC and MI, stating that modifications to the underlying Standby rates do not justify maintaining the value of the Reliability Credit for existing customers or modifying the Reliability Credit to be calculated based on Daily As-Used Demand. The JU note that the Commission has required that the Reliability Credit be applied to the Contract Demand Charge and observe that the stated purpose of the Reliability Credit is to provide a proxy of the grid value of minimizing customer usage of the grid during summer on-peak periods. The JU argue that the Commission required that the updated Standby rates include improved price signals to customers, including revised Contract Demand Charges, which in some cases will be significantly reduced or eliminated, and more granular Daily As-Used Demand Charges, both of which reflect a better measure of grid value and incentive to operate customer generation in a reliable fashion during on-peak periods than the existing Reliability Credit. Instead, the JU recommend that the Commission consider whether a Reliability Credit is still needed at all.

In its August 23 comments, MI reiterates its arguments for preserving the value of the Reliability Credit and offers additional detail regarding how it should apply to the Super-Peak Daily As-Used Demand Charge. MI states that it is flexible as to how the Reliability Credit would be modified, but also offers a potential structure whereby customers meeting pre-determined reliability criteria could be exempted from one day per month of Super-Peak Daily As-Used Demand Charges. MI states that its example structure would preserve the economic value of the existing Reliability Credit, continue to incentivize reliable operation of customers' on-site generation, and spare customers from a modest potion of the greatly increased Daily As-Used Demand Charge.

b. <u>Determination</u>

The core purpose of the Reliability Credit was to provide a financial incentive for customers to run their behind the meter DER as reliably as possible during summer on-peak periods. The Commission required expansion of the Reliability Credit as part of the 2019 Standby Rate Order in recognition that a proxy value for decreasing on-peak demands needed to be provided to customers to encourage customers to operate their generating DER as reliably as possible during on-peak periods. Up to this point, the price signals Standby rate customers have had to minimize on-peak demand have been muted by a relatively high proportion of Standby Service revenues being collected through Contract Demand Charges instead of the Daily As-Used Demand Charge.[60]

Although the Commission's decision to implement the Decision Tree methodology, as modified herein, is not outcome-oriented, nevertheless the anticipated outcome of such methodology will likely result in reductions to the utility Contract Demand Charges and concomitant increases to Daily As-Used Demand Charges. As the amount of revenue collected from Contract Demand Charges decreases, the amount collected through the highly time-sensitive Daily As-Used Demand Charges will increase and provide a stronger incentive for customers to decrease on-peak and super-peak demands, especially considering the simultaneous impact of implementation of the Super-Peak Daily As-Used Demand periods, as directed by the 2019 Standby Rate Order. Therefore, there is little need to provide a proxy value that customers would receive for reliably minimizing grid usage during peak periods when more precise methods (i.e., the revised Daily As-Used Demand rates for accurately matching cost causation with the charges customers pay for on-peak usage, Dynamic Load Management Programs for valuing reductions to a customer's typical usage pattern during high-value peak load conditions, and the Value Stack Tariff for valuing injections to the grid) are readily available. In addition, with the new Decision Tree methodology, the Commission has greater certainty that the costs recovered through each component charge are matched to their respective cost drivers.

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[60] The Contract Demand Charge does not vary based on time but only the amount of Contract Demand kW, which is based on the maximum kW demand a customer can draw. Customers have the ability to reduce such Contract Demand kW annually if they can demonstrate a durable decrease in maximum demand.

For all of the above reasons, the Commission rejects MI and NYECC's recommendations to maintain the present value of the Reliability Credit and to modify the way that the Reliability Credit is calculated. Instead, the Commission finds the JU's recommendation to consider elimination of the Reliability Credit persuasive. Customers subject to the full amount of the revised Standby Service rates established following this Order shall not be eligible to earn a Reliability Credit once such revised Standby Service rates are in effect. As discussed in greater detail below, the Commission is also implementing a modest phase-in period for customers adversely affected by the updated Standby Service rates. These customers shall continue to be eligible to earn a Reliability Credit during the period of their phase-in based on the applicable phase-in Contract Demand Charge.[61] Once a customer is fully phased-into the updated Standby Service rates they shall no longer be eligible to receive a Reliability Credit.

4. Bill Impacts on Existing Standby Service Customers

a. Comments

In its initial comments, MI expresses concern that some existing Standby customers could be harmed by the potential change in Standby rate methodology. MI notes in some circumstances the new Standby rates could result in significant detrimental rate impacts to customers and that the timing of such rate impacts during a global pandemic and economic recession is undesirable. MI states that all, or most, current Standby rate customers have presumably relied on the current Standby rate in making their decisions to invest in on-site

[61] For example, the Reliability Credit available in the third year of the phase-in shall be based on the Contract Demand Charge applicable during the third year of the phase-in.

generation, but notes that the Standby rates under consideration are dramatically different from those currently in effect. MI states that there is little that an existing Standby customer can do in response to proposed changes in Standby rates, and notes that vintaging has been frequently employed throughout this proceeding.[62] MI requests that, instead of taking service under the new Standby rates, existing customers should be accorded an option to be vintaged, that is, existing customers could continue service under existing Standby rates, subject to periodic adjustment.

In their reply comments, the JU argue that the Commission should reject MI's request to vintage existing customers. First, the JU note that maintaining two sets of Standby rates, one for vintaged existing customers and another for all others, could be complex for utilities to implement and confusing for customers. Second, the JU point out that both the 2019 Standby Rate Order and the ACOS Whitepaper recognized that bill impacts to existing customers due to rate design changes were possible, but neither recommended vintaging. Third, the JU argue that to the extent that updated Standby rates represent an improvement to the current Standby rates, and would result in some customers paying more under such improved rates, then the reason that these customers would pay more is because they have not equitably contributed to their costs for service under the current Standby rate design. Finally, the JU argue that although the present bill impact analysis shows an impact on some customers, any bill impact analysis represents only a snapshot at a given point in time based on then-present usage of the system. The JU contend that customer bill impacts will

[62] "Vintaging" is also commonly known as "grandfathering."

differ over time based on a variety of factors such as weather, changes in end-use technologies used by customers, economic activity, and operations of customer DER. The JU reiterate each of these points in their August 23 comments.

In its August 23 comments, MI reiterates many of the points it made in its initial comments, but provides additional information regarding those arguments. MI asserts that the imposition of material bill impacts on existing Standby Service customers due to a methodological change is problematic, inequitable, and should be addressed in a manner that eliminates, or at least minimizes, such impacts. MI notes that certain customers operating small on-site generators which only provide a small portion of such customer's total demand would experience large increases in Daily As-Used Demand Charge costs under the ACOS Whitepaper proposals, while customers with significant Contract Demand amounts would experience large bill increases under the JU proposals. MI contends that existing customers' reliance on the then-existing rates and rate-setting methodology was reasonable at the time, and such decisions cannot be undone now, and further argues that a majority of the existing Standby Service customers' on-site generation projects would have been developed and operational before receiving any form of notice that the Commission would be revising the then-current methodology. MI cites four examples of net energy metering (NEM) eligible technologies being vintaged into various iterations of NEM, and one example of certain DERs being vintaged into a particular valuation for the Value Stack following significant changes to the valuation of certain Value Stack components. MI asserts that it would be highly inequitable to grant some developers and certain customers vintaging options as a means of protecting the value of some DER projects, while refraining to offer similar protections to existing Standby Service customers who would experience material and detrimental impacts due to modifications in the Standby Rate design methodology.

Regarding how to implement such vintaging, MI states that the Commission could use a recommendation made in NYSEG and RG&E's Rate Panel testimony during the last NYSEG and RG&E rate proceeding to provide a mechanism to periodically update the current Standby rates for changes in revenue requirement.[63] As an alternative, if the Commission determines not to provide vintaging options for existing Standby Service customers, MI recommends that the Commission implement a gradual, extended phase-in of the newly-designed Standby rates, or allow the affected customer to return to the rates offered in its Otherwise Applicable Service Classification. MI notes that while these options should be made available to all existing Standby Service customers, those customers who are not detrimentally impacted by the newly designed rates should not be forced to continue paying the current rates.

b. Determination

The Commission is sympathetic to the plight of existing customers facing significant differences between the overall character of the rates that they relied on to make the business decision to install on-site generation, compared to the anticipated character of the rates that will be in place shortly following this Order. MI is correct that existing customers' reliance on the then-existing rates and rate-setting methodology

[63] This recommendation was made in witness testimony, but was not incorporated into the Joint Proposal filed in that proceeding or considered by the Commission in its determination on the Joint Proposal.

was reasonable at the time. The JU's argument that these customers would pay more because they have not equitably contributed to their costs for service under the current Standby rate design is not a logical conclusion, and would be potentially harmful since the opposite side of the same coin is that customers harmed by the present rate design would be owed a refund for their inequitable over-contributions. Based on the information present at the time, the current rates were reasonable, and it is reasonable that customers relied on such rates in making their business decisions.

While the Commission does not agree with MI's argument that there is little that an existing Standby customer can do in response to proposed changes in Standby rates (e.g., such customers could decide to modify their energy usage in response to the updated rates or invest in new DER) customers' initial decision to invest in the particular on-site generation technology would indeed be frustrated. Although some customers' decisions to invest in on-site generation pre-date the Commission's efforts to reform Standby Service rates, customers have been formally on notice of the potential for significant changes in Standby Service rate design since the Commission initiated its review of Standby and Buyback Service rates in the REV Track Two Order in May of 2016.[64] Further, MI's argument that the Commission has provided vintaging consideration for other customers is also flawed. There is a distinction between the Commission vintaging certain otherwise NEM-eligible customers into a specific injection compensation methodology - a value derived from special treatment compared to other

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

technologies enumerated in the PSL - and the vintaging consideration MI requests to lock certain customers into an outdated and less cost-reflective set of delivery rates.

While the Commission does find that existing customers who would be harmed by rapid imposition of a drastically different Standby rate structure deserve some level of protection, we do not find that the level of protection afforded by vintaging these customers into the existing rates for an indefinite period is warranted. Instead, as recommended by MI, the Commission finds that offering a phase-in period for customers to become familiar with the updated rate structures is reasonable. Therefore, current customers shall be afforded the opportunity to participate in a five-year phase-in period, or may otherwise choose to take service immediately under the updated Standby rates, once effective.[65] The utilities are directed to include draft tariff language effectuating the five-year phase in for existing customers, with the option to immediately take service under the updated rates, as part of their 120-day Compliance Filings, described in greater detail below.

5. Mass Market Demand Rates

a. Comments

UIU expresses its concern about developing mass market demand rates using the Decision Tree methodology in both its

[65] During the first year of the phase-in, participating customers will pay rates based on an 83.3 percent to 16.7 percent blend of the current rates and updated rates, with annual increments of 16.7 percent reduction to the blend of current rate and increase to the blend of updated rate thereafter. After the fifth year of participation, all customers will pay the full amount of the updated Standby rates. This phase-in shall also affect the Contract Demand Charge amount used to determine the value of the Reliability Credit in each year.

initial and August 23 comments, and recommends that additional analysis be performed before the Commission approves any demand rate for mass market customers. UIU states that before mass market demand rates are presented for final review, it is crucial to identify the bill impacts and complete a sensitivity analysis to understand the degree of cost shift implications due to the combination of policy goals and customer demand rate adoption. UIU requests that a comprehensive bill impact analysis comparing mass market demand rates among six different scenarios be presented to stakeholders prior to the Commission's determination in this proceeding. The six scenarios UIU requests are: 1) the current demand rate, if available for each service class; 2) rates developed based on the utilities' September 2019 ACOS filings; 3) rates developed based on ACOS studies using the ACOS Whitepaper's allocation factor; 4) rate developed based on ACOS studies using the JU's preferred CP/ICMD allocator; 5) rates developed based on ACOS studies using the JU's alternate ratio of average on-peak daily as-used demands to average contract demands; and 6) the JU's AAM proposal. UIU states that there is insufficient information presented to date to understand if the proposed JU AAM methodology is just and reasonable to implement statewide for designing mass market demand rates. UIU recommends that additional mass market rate design techniques be explored in the Working Group established under Matter No. 17-01277.

UIU also expresses concern with the requirement that mass market demand rates be developed on a revenue neutral basis. UIU states that there is a potential for intra-class subsidies which could drive up rates for customers that do not participate in the optional rate. UIU also expresses concern that investments needed to comply with the Climate Leadership and Community Protection Act (CLCPA) will increase costs to customers and that those customers that choose not to participate in the optional demand-based rates will bear an unfair proportion of such burden through an intra-class subsidy. UIU recommends that the definition of which service classes are included when designing revenue neutral rates among the investor-owned utilities is inconsistent across the State and suggests the Commission address this concern before finalizing any new rate design for mass market customers.

b. Determination

It is common practice for the Commission to consider bill impacts when deciding on rate design and/or rate level changes, especially during major rate proceedings where the outcome will impact each and every utility customer. In this instance, we are adopting a new cost allocation methodology that will impact a subset of customers that currently receive Standby rate service, and that could impact another set of customers that voluntarily choose to be served under the optional Standby rate service. For those customers that are currently on Standby rates, the Commission will require the utilities to submit bill impact statistics for those customers by service class as part of their 120-day Compliance Filings. Since the mass market standby rates are voluntary, we will not require a bill impact analysis, as UIU has requested. However, the Commission finds that knowing the impact of choosing Standby rates can be very valuable to consumers. Such information becomes even more important when combined with the installation of a distributed energy resource (DER) like solar PV, energy storage, or the purchase of an electric vehicle or electric heat pump that will require additional electricity usage.

One of the Commission's goals in offering optional Standby rates is to provide customers with the cost-based price signals that will enable the most efficient use of the electric grid as we continue to move toward achievement of New York's clean energy goals. To examine the impact of the new Standby rates on various use cases, the Joint Utilities shall consult with Staff and stakeholders to develop mass market customer bill impact analyses showing the impacts of adopting different types of DER on customer bills under the standard rates versus the Standby rates, and shall include the following scenarios at a minimum: 1) solar PV; 2) stand-alone energy storage; 3) solar PV plus storage; 4) electric vehicle charging; 5) air-source heat pumps; and 6) ground-source heat pumps. A report on the status of the bill impact analysis shall be submitted to the Commission no later than December 31, 2022. As the Commission previously directed in the 2019 Standby Rate Order, the Commission continues to expect Staff to utilize the existing VDER Rate Design Working Group for further analysis and discussion, and to provide the results for subsequent consideration by the Commission.

The Commission finds no persuasive reason to abrogate the determination in the 2019 Standby Rate Order to develop mass market demand-based rates on a revenue neutral basis compared to the parent service classification. UIU's concern regarding customers taking advantage of the more cost-reflective Standby rates developed through the application of the Decision Tree, as modified herein, thereby resulting in a subsidy paid by non-participants to cover costs incurred by participants, is misplaced. Given that customers on Standby Rates will have rates that cover their costs, those Standby Rates customers will not receive a subsidy. Any increase in non-participating customers' bills merely reflects a different allocation of the revenue shortfalls experienced by the service classification as a whole. Further, as directed in the 2019 Standby Rate Order, mass market optional demand rate participants are included in their parent service classification's RDM, and therefore will continue to contribute toward any revenue shortfalls experienced by the service classification.

UIU's concern that non-participating customers provide a subsidy to participating customers making use of investments needed to comply with the CLCPA, namely building and transportation electrification technologies, is similarly off the mark. Technologies like ground-source heat pumps and well-managed electric vehicle charging, where customer usage during on-peak periods is either not affected or decreased relative to other technologies typically have the opposite impact of UIU's concern, in that such customers both pay for the technologies that the Commission seeks to accelerate, and also pay delivery rates higher than their fair share under traditional volumetric mass market rates since their monthly usage increases while their contribution to system costs either stay the same or decrease.

The Commission has previously recognized this impact in its approval of a Rate Impact Credit for customers installing ground-source heat pumps at Central Hudson and O&R.[66] At each utility the Commission approved a Rate Impact Credit only for a limited time, expiring when customers would become able to

[66] See Cases 17-E-0459 et al., Central Hudson - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued June 14, 2019), pp. 26, 55-56; see also, Cases 18-E-0067 et al., Orange and Rockland - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019), pp. 79,82.

participate in more advanced and cost-reflective delivery rates. Similarly, although the same Time-of-Use rates are available for all residential customers, the Commission has previously approved special provisions within each utility's optional Time-of-Use rates for residential customers which are available only for Electric Vehicle owners. As noted in the 2019 Standby Rate Order, providing optional mass market demand-based rates advances New York State's policy goals of promoting more efficient use of energy, achieving deeper penetration of renewable energy and DERs, as well as promoting market solutions to achieve greater use of advanced energy management products.[67] For the above reasons, the Commission reject's UIU's request to reconsider implementation of revenue neutral optional mass market demand-based rates.

UIU does raise a salient concern, however, in its illustration of inconsistent application of revenue neutrality to various residential service classifications across the utilities. UIU correctly notes that some utilities separately track "typical" residential customers and residential customers participating in Time-of-Use rates in their ECOS studies. Therefore, the Commission directs the utilities, as part of their 120-day Compliance Filings, to include a description of whether the mass market optional demand-based rates are designed to be revenue neutral to some or all of the overall applicable service classification.

6. Other Rate Design Issues

a. Comments

In its reply comments, NECHPI requests that various other issues related to Standby Service be streamlined.

[67] 2019 Standby Rate Order, p. 15.

Specifically, NECHPI and NYECC/MTA request that the Commission modify the process for determining the amount of Contract Demand kilowatts (Contract Demand kW) to be based on a customer's peak demand on a rolling two-year timeline instead of being assessed based a customer's highest historical demand. NECHPI notes that there is currently no ready avenue for customers to revise their Contract Demand kW downward, and asserts that its recommended modification would incentivize customers to invest in energy efficiency and distributed generation to permanently decrease their peak load. In their August 23 comments, NYECC/MTA state that they agree with NECHPI's proposals regarding determining Contract Demand kW.

b. Determination

How, specifically, utilities define and set a customer's Contract Demand kW, and how frequently such Contract Demand kW amounts are revised either by the customer or the utility, is beyond the scope of this proceeding. Further, NECHPI is incorrect in its assertion that customers have no avenue for revising their Contract Demand kW, as customers already have the option to decrease their Contract Demand kW annually, after showing that they have completed energy efficiency or other projects to decrease peak demand. Therefore, the Commission declines to implement the other rate design related proposals requested by NECHPI and NYECC/MTA.

Buyback Rates and Exemption for Stand-Alone Storage

As part of the bill impact analysis Staff performed in reviewing the potential impact of its proposed Decision Tree methodology, Staff observes that its proposed methodology results in reasonable Standby and Buyback Service rates for most customers, but that additional consideration is required for stand-alone energy storage systems, which would be more impacted than other applications. As a result, Staff recommended that the Commission provide near-term relief to allow stand-alone energy storage systems to gain greater penetration in the market by providing a limited exemption from Buyback Service Contract Demand Charges related to such systems' injections to the grid.

Specifically, Staff recommended that the Commission implement a 20-year exemption for stand-alone energy storage systems interconnected and operational by December 31, 2025.[68] Staff explains that the deadline for participating stand-alone energy storage systems was selected to coincide with the interim storage target.[69] Staff notes that a 20-year term would allow the exemption to continue throughout a project's useful life, including allowing for battery cells to be repowered to maintain rated capacity, if needed.

Staff's recommended exemption would include systems which have already been installed, with an exception for those units contracted under a utility Non-Wires Alternative (NWA) project that did not receive a NYSERDA Market Acceleration Bridge Incentive. Staff reasons that granting this exemption to already-contracted NWA resources would result in an unreasonable windfall to these customers. Staff also recommended that those customers that were awarded a NYSERDA Market Acceleration Bridge Incentive under the Rest of State Blocks 1-3, Con Edison Westchester Block 1, or Con Edison New York City Blocks 2-3 only be eligible to participate in the Buyback Service Contract Demand exemption if such customers forfeit $50 per kilowatt-hour

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[68] Staff also recommended that the Commission not impose specific capacity limitations, reasoning that such limits could increase development risk and either stifle the market for stand-alone energy storage or lead to increased financing costs for such projects.

[69] Storage Order, p. 12.

of the incentive amount awarded by NYSERDA, noting that the incentive awards provided by NYSERDA had included assumptions regarding Buyback Service Contract Demand Charge costs, which would no longer be accurate. Staff notes that participant forfeitures as a result of the exemption would be put to use toward further energy storage incentive programs.

Staff posited that this exemption would be unlikely to cause significant bill impacts to other customers. Staff argues that the potential for cost-shifts would be small due to a relatively small number of stand-alone energy storage projects which would be eligible, and any such cost-shifts would be outweighed by other benefits, especially as electric vehicle and other DER penetration continues to increase.

1. Appropriateness of Standby and Buyback Charges

a. Comments

In its initial comments, MGN argues that energy storage systems should be completely exempt from Standby Service and Buyback Service. MGN states that the charges imposed on energy storage system operators for transport and delivery of electricity should reflect market costs at the time of charging,[70] and energy injected into the distribution system at times when it is of highest value should neither be subjected to the same rate treatments as load nor subjected to demand charges to deliver it to the utility. MGN notes that energy storage units co-located with distributed solar systems are exempted from both Standby Service and Buyback Service, and argues that stand-alone energy storage resources should not be treated differently. MGN argues that imposing both Standby Service rates and Buyback Service rates on the same customer represents

[70] Customers are charged the market price for withdrawals from the system through the Supply Charge.

a double payment, and that implementing the ACOS Whitepaper proposal would cause energy storage customers that export more than they withdraw to have to pay one Customer Charge under Standby Service and another Customer Charge under Buyback Service.[71] In its reply comments, NineDot concurs with MGN's comments.

Similarly, in its initial comments, NY-BEST argues that Buyback Service Contract Demand Charges should not be imposed on customers at all. NY-BEST argues that DERs with the ability to export to the grid are required to go through an interconnection study and potentially pay for required upgrades to the system to allow such injections. Therefore, injections that drive material costs to the grid or those than can be damaging should be fully addressed in the interconnection study process and associated upgrades. NY-BEST also posits that New York is the only state to authorize Buyback Service charges related to injections to the grid that exceed Standby Service demands. NY-BEST concludes that Buyback Service Contract Demand Charges represent an unnecessary hurdle to energy storage development.

In their initial comments, the JU argue that charging injecting customers under Buyback Service rates is appropriate.

[71] MGN's comments are incorrect in this regard. The Customer Charge applicable to Buyback Service is waived if the customer is also a Standby Service customer. Therefore, each customer, whether taking Standby Service only, Buyback Service only, or taking both Standby and Buyback Service, only pays a single Customer Charge. In addition, Buyback Service Contract Demand is only charged to customers for any amount incremental to the Standby Service Contract Demand. While a customer may pay both a Standby Service Contract Demand Charge and a Buyback Service Contract Demand Charge, such customers only pay one Contract Demand Charge for each applicable kW of either Standby or Buyback Service Contract Demand.

The JU posit that the Buyback Service Contract Demand Charge provides both an appropriate price signal to size maximum injections and to help the electric distribution utility anticipate power flows.

In their reply comments, the JU urge the Commission to reject both MGN and NY-BEST's arguments that Standby and/or Buyback Service rates should not apply to energy storage systems. The JU urges the Commission to reject MGN's request, arguing that it is reasonable for an energy storage system that uses the distribution system to contribute toward the costs of that system. Regarding MGN's arguments that Standby and Buyback Service Buyback Service rates represent a double payment, the JU state that mechanisms are in place to resolve any potential over-recovery of distribution charges, specifically RDMs and periodic revisions to billing determinants used in revenue allocation and rate design in future rate proceedings. The JU maintain that this provides the vehicle for addressing any over-recoveries of system charges in aggregate.

The JU request that the Commission reject what it characterizes as NY-BEST's request for special treatment for energy storage systems, such as the elimination of the Contract Demand Charge, due to the value of energy storage injections. The JU argue that NY-BEST's request would allow energy storage resources to pay virtually nothing to access the distribution system, and treat energy storage resources differently than other similarly situated customers that inject electricity from other forms of DERs. The JU contend that NY-BEST ignores the fact that in order for energy storage resources to obtain revenues from participating in wholesale markets and other utility compensation programs (e.g., NWA projects), such resources must connect to the utility system and that without connecting to the system there is no value proposition for energy storage.

In its reply comments, NY-BEST states that, contrary to the JU's position in its initial comments, Buyback Contract Demand Charges are not an appropriate price signal but rather serve solely as a barrier to prevent energy storage systems from exporting more power than they import. NY-BEST argues that the only costs energy storage systems cause via export are identified in interconnection studies and paid for by the interconnection applicant through interconnection charges. Moreover, NY-BEST contends that Buyback Service Contract Demand Charges are non-seasonal and non-time differentiated charges applied to exports on the basis of speculative assumptions regarding cost causation, which also carry financially devastating penalties for exceeding the specified Buyback Contract Demand limits. NY-BEST requests again that Buyback Service Contract Demand Charges should not be imposed for energy storage systems that are not utility-controlled. NY-BEST states that contrary to the JU's assertions, third-party owned energy storage resources dispatched by utilities currently pay Buyback Service Contract Demand Charges, and further alleges that the JU's comments appear to express a preference for utility control and/or ownership of energy storage assets.[72] NY-BEST argues that this is in conflict with efforts to establish a merchant energy storage sector with dual participation in the wholesale and retail markets.

b. Determination

This issue of whether Standby and Buyback Service rates should apply to energy storage systems has been considered

[72] For example, as part of a Non-Wire Alternative project.

in multiple previous Commission Orders, most recently the 2019 Standby Rate Order,[73] and before that in the 2018 Storage Order,[74] and the 2018 Value Stack Expansion Order.[75] In each of these previous orders, the Commission has determined that customers with energy storage systems should be subject to Standby and Buyback Service, if not exempted for some other reason (e.g., if the energy storage system is co-located with an exempt technology).

MGN, NineDot, and NY-BEST's comments alleging that it is inappropriate to require energy storage systems to take Standby and Buyback Service are unpersuasive. As explained in the Storage Order, Standby and Buyback Service rates are designed to match the costs that individual customers impose on the system with the rates that such customers pay.[76] As further discussed in the 2019 Standby Rate Order, the accuracy of these price signals will be further improved with the more granular rate structures approved therein.[77] This Order adopts the Decision Tree methodology, which will even more closely tie the rates and charges customers pay with cost causation principles. In addition, as discussed in the 2019 Standby Rate Order, the Commission recognized that the costs that customers must pay to safely interconnect to the utility system, paid by the customer through interconnection charges, are separate and distinct from

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[73] 2019 Standby Rate Order, pp. 55-62.

[74] Case 18-E-0130, Storage Proceeding, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) pp. 12-21 (Storage Order).

[75] Case 15-E-0751, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018), pp. 17-18) (Value Stack Expansion Order).

[76] Storage Order, pp. 14-15.

[77] 2019 Standby Rate Order, pp. 33, 61.

the costs the utility must incur to serve the customer once it is safe to connect, paid for through Contract Demand Charges.[78] The Commission finds insufficient evidence presented in this proceeding to countermand its previous findings in the Storage Order and 2019 Standby Rate Order.

Instead, the Commission finds that Standby and Buyback Service, and their respective rates, are appropriate to apply to energy storage systems. Standby and Buyback Service rates are distinctly applicable to energy storage systems. The close matching of cost causation and cost recovery provided by Standby and Buyback rates is especially important when a customer uses a technology which allows them to shape their usage patterns to be opposite of the bulk of the customers included in the same service classification.

MGN and NineDot's argument that the Commission would be providing disparate treatment for stand-alone energy storage systems compared to exempt energy storage systems which are co-located with other exempt technologies is similarly unpersuasive. It is the co-located energy storage units which are enjoying the disparate treatment provided by their exemption from Standby and Buyback Service under PSL §66(j), et al., not the Commission's determination not to extend such an exemption to an otherwise non-exempt technology.

While the Commission confirms that energy storage systems should be subject to Standby and Buyback Service and their associated charges to ensure they pay fair and reasonable rates assigned to them in accordance with cost causation principles, the Commission anticipates that further consideration will be given in the near term to the tariff and

[78] 2019 Standby Rate Order, pp. 61-62.

rate structures applicable to storage resources. Notably, Staff and NYSERDA are expected to update the Storage Roadmap and to identify recommendations for the Commission's consideration. The Commission recognizes that energy storage systems will be a critical technology to meeting the State's energy and environmental policy goals and will consider any such recommendations to further support the proliferation of storage resources throughout New York State.

2. Buyback Service Impacts on Wholesale Markets

a. Comments

In its initial comments, GlidePath posits that Buyback Charges, and demand charges of all types, are neutral to the energy storage unit, but may result in higher market prices if energy storage resources are on the margin. GlidePath argues that minimizing demand charges to the extent possible, even beyond the proposed exemption from Buyback Service charges, will advance the State's goals and further the development of energy storage resources.

In their initial comments, the JU argue that Buyback Service rates are not generally applicable to wholesale market generators providing energy, ancillary services, and capacity in the wholesale market. The JU state that Standby Service rates do apply to wholesale generators connected to utility systems, including those that take station service from the NYISO. The JU aver, however, that Standby Service Contract Demand Charges are unlikely to impact an energy storage system's day-to-day participation in NYISO markets and are unlikely to affect bidding behavior for ancillary or energy services. The JU admit that while Standby Service Contract Demand Charges could have a modest impact on a market participant's capacity bids, the impact of such charges on the clearing prices of the broader capacity market are likely to be negligible. The JU posit that since there are minimal impacts on the wholesale market, costs associated with infrastructure that specifically serves a customer (i.e., Standby and Buyback Contract Demand Charges) should be recovered from that customer.

In its initial comments, NY-BEST highlights that changes to utility Buyback Service rates could make a significant impact on a customers' ability to participate in wholesale markets. As a threshold matter, NY-BEST states that Con Edison's Rate O Wholesale Distribution Service (WDS), is derived from that Company's Buyback Service rates, and that Con Edison has successfully persuaded the FERC to accept such rate in deference to the New York Commission's determination that the Standby Service rates were just and reasonable.[79] NY-BEST states that while the other utilities do not currently have effective WDS tariffs, NY-BEST anticipates that when the utilities make WDS filings before the FERC those filings will be either identical or extremely similar to the Commission-approved Buyback Service Rates.

NY-BEST contends that Buyback Service charges pose a barrier for energy storage systems to respond to market prices, resulting in an economic cap on the amount of capacity an energy storage resource can provide in capacity markets, and limiting energy storage systems' ability to fully participate in reserve markets. In particular, NY-BEST notes that the penalties related to energy storage systems exceeding their Contract Demand kW amounts preclude energy storage systems from fully maximizing injection demands, regardless of price signals from the wholesale market or during emergency conditions. NY-BEST

[79] WDS tariffs are also known as Open Access Transmission Tariffs (OATTs).

forecasts that Buyback Service demand charges will stymie the NYISO's efforts to reduce reliance on "out of merit" fossil fuel-fired generating stations through its creation of sub-zonal reserve pockets with NYISO Zone J.

In their reply comments, the JU respond to Glidepath and NY-BEST's comments. The JU state that Glidepath's argument that demand charges included in energy storage resources' capacity bids would increase costs to all customers is incorrect. The JU argue that energy storage resources may not participate in the wholesale markets or set market prices, and that the impact of Contract Demand Charges on capacity prices is likely to be negligible. The JU assert that Standby Service Contract Demand Charges, which can be reset annually, are unlikely to impact a storage units day-to-day participation in the NYISO energy and ancillary services markets. The JU state that while the Con Edison WDS Tariff is the only FERC OATT in effect, they believe that Con Edison's WDS Tariff is an appropriate model for other utilities' future OATTs.

The JU state that they oppose NY-BEST's essential argument that stand-alone energy storage systems should be granted free use of the utility distribution system to participate in wholesale markets. The JU note that the Commission has approved Contract Demand Charges to reflect a customer's maximum potential demand that it might place on the utility's system, and that the utility must build infrastructure to meet such maximum demand. As the JU observe, Buyback Service Contract Demand Charges only apply to the amount of Contract Demand in excess of the Standby Service Contract Demand. The JU argue that Con Edison's Buyback Service customers elect their own level of Buyback Service Contract Demand, and that energy storage customers can manage or avoid Buyback Service Contract

Demand exceedance fees through their own bidding behavior in the NYISO markets. The JU state that Contract Demand exceedance fees are designed to ensure that the customer is paying for its share of the utility's distribution system, and that the Buyback Service Contract Demand Exceedance Fees imposed on a customer demonstrate the higher level of service required by the customer than what such customer had been paying for. The JU contend that although NY-BEST provided comments suggesting that Contract Demand Exceedance Fees may stifle participation in short-duration markets, the impacts of high short-duration demands resulting from participation in the reserves market would be lessened due to longer demand measurement intervals used for billing purposes, resulting in smaller demand values.

In its reply comments, NY-BEST states that Standby and Buyback demand charges can contribute to energy storage resources being subject to NYISO Buyer-side Mitigation rules. NY-BEST states that energy storage resources are evaluated against the Cost of New Entry when the NYISO determines whether to apply minimum bid requirements known as Buyer-side Mitigation (BSM). As evidence of these impacts, NY-BEST points to a recent NYISO market monitoring report identifying that only three of the thirteen energy storage projects passed BSM tests for the 2019 class year, and that the report identified distribution utility charges as the first reason why such units failed the BSM tests. NY-BEST argues that failing the BSM requires that energy storage resources bid a higher price into the market, and that such mitigation can result in higher prices for consumers, especially in constrained areas where the pricing for a relatively small amount of wholesale resources can have a significant impact on the clearing prices of capacity markets.

b. Determination

The Commission appreciates the significant level of details provided by stakeholders on the potential impacts of buyback charges on wholesale market participation by energy storage projects. Based on our review, the Commission finds that the Buyback Service rules, regulations, and charges have a direct impact on customers participating in the wholesale markets while connected to a utility's distribution system. This finding is taken into account below where we address the exemption from buyback rates.

3. Buyback Exemption

a. Comments

In their initial comments, Borrego, GlidePath, NY-BEST, NYECC, and Soltage recommend that the Commission adopt the ACOS Whitepaper's proposal to exempt standalone energy storage from Contract Demand Charges under Buyback service. The City states that the proposed exemption is a beneficial effort that will encourage deployment of energy storage systems, and that such systems will play a critical role in achieving the City and the State's policy goals. Borrego argues that exempting stand-alone energy storage projects from Contract Demand Charges to avoid adverse outcomes will improve project economics and enable NYC to become an unsubsidized market for these resources within the next few years.

In support of the Buyback Exemption, Soltage highlights that energy storage projects serve a different purpose than the traditional distributed generation plants for which Standby and Buyback Service rates were initially designed, namely by injecting power into the grid during peak times instead of mainly reducing demand behind customer meters and injecting to the grid only when excess power production cannot be consumed on site. NYECC, while supportive of the overall Buyback Exemption proposal, cautions that the bill impacts on other customers for this exemption need to be transparently provided to ascertain the duration of such an exemption in the long term. The City argues that the proposed exemption is rational considering the benefits provided to the system by energy storage. GlidePath agrees with the ACOS Whitepaper's proposal that if the exemption is limited it should be managed on a deadline basis rather than by limiting the number of facilities eligible, and further asserts that the cutoff for eligibility should be clear and under the reasonable control of the developer in order to allow developers to confidently invest in advancing projects.

While supportive of the Buyback Exemption proposal overall, the City, MGN, NY-BEST, and Soltage, in their respective initial comments, and NineDot in its reply comments, recommend various modifications. First, the City, MGN, NY-BEST, Soltage and NineDot recommend that the Commission extend the Buyback Exemption in-service date deadline to December 31, 2030. The City, MGN, NY-BEST, Soltage, and NineDot each note that the Whitepaper's proposed in-service date of December 31, 2025, would result in an exemption that would only be available to energy storage projects that are commenced in the next two years due to long interconnection process timelines. NY-BEST argues that, because energy storage project development cycles are often two years or more, the Whitepaper's proposed in-service date deadline of December 31, 2025, may result in a boom-or-bust cycle of rapid early development that grinds to a halt in early 2024. NY-BEST also takes issue with the ACOS Whitepaper's proposal that existing energy storage projects participating in an NWA Project be prohibited from also participating in the

Buyback Exemption. NY-BEST argues that not extending the Buyback Exemption to customers participating in existing NWA Projects is discriminatory ratemaking, and that any windfall realized by an NWA project developer should be subject to negotiation between the NWA Project contract counterparties.

Second, MGN recommends that the Commission should not limit the proposed exemption to Buyback Service Contract Demand Charges for stand-alone energy storage systems to 20 years, but should instead allow the exemption to remain in place until the participating systems are required to be decommissioned, either by contract or due to degradation of the components. MGN notes that a large portion of capital costs associated with the energy storage system, such as land, foundational infrastructure, and interconnection facilities, have useful lifetimes in excess of 40 years, and that an energy storage system can be repowered to extend its useful lifetime beyond 20 years. MGN further argues that there should not be a defined time limit on the proposed exemption on Buyback Service Contract Demand Charges since co-located energy storage systems are exempt from Standby and Buyback Service.

In their initial comments, both UIU and the JU argue that the Commission should reject the Buyback Exemption. UIU asserts that there has been no analysis to support Staff's proposal to exempt stand-alone energy storage customers from Buyback Service Contract Demand Charges. The JU present four main arguments against the proposed Buyback Exemption. First, the JU argue that the proposed Buyback Exemption is contrary to previous Commission directives that Standby and Buyback Service Contract Demand Charges should apply to energy storage systems, noting that the Commission has previously rejected this type of exemption because such an exemption would allow projects to avoid being charged an appropriate amount to support the electric grid.

Second, the JU assert that the Commission should not ignore the potential bill impacts of granting the proposed exemption on other customers, especially given the 20-year duration of the proposed exemption. The JU caution that, contrary to ACOS Whitepaper's claim that the impact of the proposed exemption on other customers would be small, the impact of accepting a Buyback Exemption on customers could be significant. The JU forecast that the impact of 150 MW of energy storage (i.e., about half of the energy storage systems in Con Edison's interconnection queue) participating in the exemption could result in approximately $7.5 million in uncollected Buyback Service Contract Demand Charge revenue per year, or about $150 million over the lifetime of the 20-year exemption.[80] The JU argue that the ACOS Whitepaper's assertion that the increase in stand-alone energy storage projects will be small also ignores lessons learned from similar rate-based programs such as Net Energy Metering (NEM), where customer adoption of NEM-eligible technologies rapidly outpaced deployment forecasts and required multiple program cap increases. The JU also express concern that the ACOS Whitepaper's proposal to retroactively apply the exemption to existing stand-alone energy storage facilities would create a windfall for those customers at the expense of others.

Third, the JU contend that although the ACOS Whitepaper generally stated that energy storage injections are

[80] The JU price out the impact of the Buyback Exemption using the current monthly rate for an SC 9 Rate V Low Tension customer - $8.04 per kW of Contract Demand – assuming that the 50 MW of energy storage capacity will result in 25 MW of Buyback Service Contract Demand.

broadly beneficial, it is possible that injections could impose costs on the electric system, instead of reducing costs. As an example, the JU posit that if energy storage systems export power during periods of low load, such export could lead to curtailment of intermittent renewable resources, instead of increasing their hosting capacity. While the JU admit that future dispatch and coordination paradigms may be developed to manage these constraints, the ACOS Whitepaper does not include any proposals on how to ensure that stand-alone energy storage systems are operated in a manner that is beneficial to the grid rather than cost-causative, and therefore Buyback Service Contract Demand Charge should continue to be imposed on stand-alone energy storage systems in the near term. The JU assert that the Buyback Service Contract Demand Charge is a useful tool in encouraging the appropriate sizing and operation of stand-alone energy storage systems, and therefore a blanket 20-year exemption is likely to impose cost shifts on non-participating customers and lead to an incremental increase in utility costs as the level of energy storage adoption increases.

Fourth, the JU state that the proposed Buyback Exemption is not the ideal delivery method for providing a technology-specific incentive. Instead, the JU recommend that it would be a sounder and more transparent policy to explicitly provide incentives to desired technologies which can be periodically reset, for example through a NYSERDA program. The JU argue that static incentives embedded into rates cannot adjust quickly enough to meet evolving technological and market changes as they occur and could instead hinder the transition to the more advanced technologies as they develop. The JU recommend that, instead of approving the Buyback Exemption, the Commission should enhance utility or NYSERDA incentive programs if the existing incentives are not sufficient to spur the desired amount of energy storage development.

In their initial comments, both UIU and the JU also offer recommendations for modifications to the Buyback Incentive if the Commission determines to approve such exemption despite their opposition. UIU recommends that the Commission impose a maximum cost-shift cap. The JU recommends that if the Commission decides to implement a Buyback Exemption, it should be shorter and more limited than what was proposed in the ACOS Whitepaper. The JU assert that the exemption should be limited to the first 50 MW of stand-alone energy storage and only applicable for a five-year duration. The JU state that the 50 MW capacity limit is aligned with Con Edison's Distributed System Implementation Plan, which itself is derived accounting for the current trajectory for stand-alone energy storage systems based on the amount of capacity of such systems currently in Con Edison's interconnection queue. The JU assert that an exemption duration of five years is a reasonable amount of time to determine how successful the incentive is at driving energy storage penetration, and to provide for appropriate adjustments going forward.

In their reply comments, AEEI, the City, NineDot, and NY-BEST continue to express support for the Buyback Exemption and address the JU's arguments against it. AEEI states that near-term relief from Buyback Service Contract Demand Charges are necessary to improve the economics of stand-alone energy storage systems, particularly in downstate utility service territories. The City asserts that the JU's argument that additional support for energy storage projects is not needed is unfounded, since the 2021 State of Storage Report found that the cumulative energy storage projects deployed at the end of 2020 was 1,186 MW, or 79 percent of the 2025 storage penetration goal, and only 40 percent of the 2030 target.[81] NY-BEST argues that the Buyback Exemption will provide time for the Commission and stakeholders to determine if the reformed Standby and Buyback rate designs resulting from this proceeding are sufficient to accurately capture the cost causation and benefits from stand-alone energy storage resources, as well as give such resources time to refine their business models to accommodate the new Standby and Buyback Service rates.

NY-BEST maintains that while the JU argue that the impacts of the Buyback Exemption to customers will be material and that the impacts on the NYISO market from Standby and Buyback charges will be negligible, the opposites are true. According to NY-BEST, the JU’s prediction on the magnitude of the cost-shift resulting from approval of the Exemption is overly optimistic in terms of the amount of energy storage deployed, and that the JU over-stated the valuation of the Exemption based on the Buyback Service Contract Demand Charge currently in place at Con Edison. Furthermore, NY-BEST argues that the JU’s citation of the solar market as a cautionary tale for over-incenting energy storage resources is misplaced, as energy storage resources will continue to pay the Standby Service rates developed through this proceeding.

In their reply comments, AEEI, the City, and NineDot also recommend or support certain modifications to the Buyback Exemption. The City asserts that a longer eligibility period, to December 31, 2030, is necessary to provide energy storage resources with sufficient assurance that the exemption will

[81] Case 18-E-0130, Storage Proceeding, Second Annual State of Storage Report (filed April 1, 2021) (2021 State of Storage Report).

still be available by the time their projects are complete. NineDot recommends that qualification for the Buyback Exemption should be based on either 1) the date that the developer makes a 25 percent deposit toward interconnection costs for a project to the relevant distribution utility, or 2) the date of an executed interconnection agreement if a deposit is not required. NineDot argues that using an in-service date deadline, as proposed in the ACOS Whitepaper, is inconsistent with other eligibility qualifications under the Value Stack Tariff, all of which have been based on the date of the 25 percent interconnection cost deposit. AEEI states that while it does not endorse a specific in-service date deadline, it recommends that if the Commission extends such deadline through 2030, then a midpoint review process may be warranted to determine if energy storage economics have changed and whether the Buyback Exemption remains necessary.

NineDot also recommends that the Buyback Exemption should last for at least 25 years. NineDot states that the proposed 20-year duration of the exemption is inconsistent with other terms of the Value Stack Tariff, including NYSERDA's typical timeframe for evaluating the economics of projects participating in the Value Stack Tariff. NineDot further argues that the 20-year exemption duration proposed in the ACOS Whitepaper would potentially result in energy storage equipment being abandoned instead of repowered, since energy storage equipment will typically require repowering after 15 years and financiers would be heavily exposed to unknown structural changes in operating costs in the last five years of the Buyback Exemption.

In its reply comments, the JU argue that the Buyback Exemption is unnecessary and expensive. First, the JU argue that the ACOS Whitepaper's Buyback Exemption is contrary to Staff's conclusions included in the 2021 State of Storage Report. The JU note that 2021 State of Storage Report found that the amount of storage already deployed, or that has been awarded or contracted for, amounts to 79 percent of the 2025 target and 40 percent toward the 2030 target, and that were over 8,000 MW of energy storage capacity in the NYISO interconnection queue at that time. Further, the JU argue that there has been significant growth in energy storage system installations without the Buyback Exemption, and, quoting the 2021 Storage Report, "the portfolio of programs and actions approved by the Commission… has effectively accelerated New York's energy storage market."[82]

The JU point out that while the 2021 State of Storage Report does mention the ACOS Whitepaper, it does not discuss the Buyback Exemption in any detail nor offer any justification for such exemption, and instead finds that "no corrective actions to the Commission's energy storage deployment policy are necessary at this time."[83] Using the same cost assumptions as their previous estimation of the potential cost-shift, the JU forecast that the impact of providing a Buyback Exemption to all energy storage systems needed to achieve the 3 gigawatt (GW) goal by 2030 could be almost $3 billion.

The JU's reply comments also address specific comments submitted by Borrego and NY-BEST. The JU assert that NY-BEST and Borrego imply that, absent Commission approval of the Buyback Exemption, the increase in stand-alone energy storage projects is likely to be small and therefore the CLCPA goals

[82] 2021 State of Storage Report, p. 3.

[83] 2021 State of Storage Report, p. 24.

cannot be met. The JU argue that this argument ignores robust growth in the storage industry without the Buyback Exemption to date. The JU contend that Borrego's argument that the Buyback Exemption would allow New York City to become an unsubsidized market for energy storage is incorrect. The JU note that the existing NYSERDA incentives preclude the energy storage market from being unsubsidized currently, and that subsidies for the energy storage market would be locked in until at least 2045 if the Commission approves the Buyback Exemption. The JU argue that the need for the Buyback Exemption is lessened if the cost of stand-alone energy storage levels declines to a level where subsidies are no longer needed within the next few years, as forecast by Borrego.

b. Determination

There are four key considerations underlying the Commission's determination on the threshold matter of whether additional incentives for stand-alone storage are reasonable. The first consideration is what the impact of additional stand-alone storage would be. The JU's argument that increased energy storage system penetration could result in backing-down renewable resources is unpersuasive, as this hypothetical requires that we lay aside the core business model for stand-alone systems (i.e., that energy storage systems charge during low-cost periods and discharge during high-value periods). The Commission instead agrees with most stakeholders that an increased amount of stand-alone storage would be necessary in meeting State and local policy goals, and that the typical anticipated operation of such systems would support, not exacerbate, distribution system needs.

The second consideration is whether there is a need for additional incentives to support the stand-alone segment of the energy storage market. Both the City and the JU point to the same figures from the 2021 Storage Report, albeit to support different conclusions. As noted therein, as of the end of 2020, cumulative energy storage penetration was equivalent to 79 percent of the 2025 goal and 40 percent of the 2030 goal. The City suggests this is evidence that energy storage systems continue to need out-of-market support, while the JU concludes the same information indicates that energy storage systems are on track to meet State energy storage deployment goals without further support. The crux of the JU's argument is that the energy storage market is growing sufficiently without further incentives, and that the Commission should not consider additional support since the 2021 State of Storage Report did not specifically call for specific additional action beyond the programs in place at that time. While the 2021 State of Storage Report may not have called for corrective actions for the entire energy storage market, it is clear that additional consideration should be made for the stand-alone segment of that market in light of the Commission's findings that energy storage has a critical role to play in meeting New York's CLCPA goals, as discussed in the recent Power Grid Study Order.[84]

The third consideration that the Commission considers is the possible costs of the proposed Buyback Exemption, and whether such costs are worthwhile. As a threshold matter, with rate or charge exemptions there are no incremental societal costs. However, as identified by UIU and the JU, there is a potential for cost shifts among utility customers, since the

[84] Case 20-E-0197, et al., Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Power Grid Study Recommendations (issued January 20, 2022) (Power Grid Study Order).

same amount of delivery revenue must be collected from customers, but some customers have been exempted from contributing to a portion of such revenues. While the JU's forecast of potential cost-shifts related to the Buyback Exemption is concerning, the estimate does provide a useful benchmark in considering whether the potential cost shifts resulting from the Buyback Exemption are reasonable.

The JU estimate that the potential 20-year cost shift of 50 MW of stand-alone energy storage connecting to Con Edison's system would be approximately $150 million, or about $7.5 million per year. While $7.5 million per year is not insignificant, it bears comparison to the approximately $2.2 billion of annual revenue requirement collected from the affected service classification, an impact of approximately 0.3 percent.[85] Therefore, we find the ACOS Whitepaper and NY-BEST's arguments persuasive that the cost shifts resulting from implementing the Buyback Exemption are likely to be relatively small.

The magnitude of the cost shift that will actually be experienced by customers as a result of the Buyback Exemption is very difficult to accurately forecast. While estimating the potential cost shifts may be a useful exercise in determining the potential maximum impact of the Buyback Exemption, as recommended by NYECC, the true impacts of any cost-shift are unknowable until after the fact. The magnitude of any cost shift will vary with at least three factors, including: 1) the amount of Buyback Contract Demand kW that is actually exempted, 2) the Buyback Contract Demand rate on a dollar per kW per month basis that would otherwise be charged to exempted customers, and

[85] Case 19-E-0065, Con Edison - Rates, Joint Proposal (submitted October 18, 2019), Appendix 4, p. 3.

3) whether the amount of revenues actually collected from the overall service classification are less than, equal to, or greater than the pre-set revenue requirement for that class. The first two factors are self-explanatory – cost shifts have a direct relationship with both the amount of Contract Demand kW exempted and the rate charged for each kW of exempted Contract Demand. As both or either factors increase, the level of cost shifts must also increase. However, since revenues to be collected from a class of customers is set ahead of time based on a forecast of number of customers and an amount for each relevant billing determinant, if a class of customers and their associated billing determinants grow faster than the forecasted rate, excess revenues generated by such incremental customers may result in lower bills to all other customers, resulting in refunds provided through the RDM or the true-up mechanism approved in this Order. While this impact is limited (i.e., likely no more than three years) it could result in a moderate decrease in the amount of cost shift actually experienced given the limited duration of the Buyback Exemption.[86] In the short term, other customers may experience bill decreases resulting from greater than anticipated revenues due to participating customers incentivized to install energy storage systems at a higher than forecast rate due to the additional support provided by the Buyback Exemption. In the long term, stand-alone energy storage customers may contribute to system costs less than other customers, lowering long term bills for all members of the service class.

[86] For example, if the cost shift from a particular project is avoided for three years, the overall impact of the cost-shift from that project would have been reduced by 20 percent.

Although the JU point to NEM as a cautionary tale for how exemptions from certain rate structures can result in unexpectedly rapid adoption of particular technologies and result in large cost-shifts among customers, the JU's analogy is not apt. Customers eligible for NEM are essentially exempted from all costs of maintaining the system beyond the costs included in the Customer Charge, including delivery charges, surcharges collected on a per-kWh basis, and per-kWh supply charges, provided that NEM customers monthly kWh generation is greater than their monthly kWh usage. This would be akin to a stand-alone energy storage customer being exempted from the Standby Service Contract Demand Charge, the Buyback Service Contract Demand Charge, with injections netting out any Standby Service Daily As-Used Demand Charges. Instead, stand-alone energy storage systems would only be exempted from paying Buyback Service Contract Demand Charges, and would still pay the applicable Standby Service rates, as noted by NY-BEST. While the JU is correct that not collecting costs associated with stand-alone energy storage customers' Buyback Service Contract Demand Charges will cause some level of cost shift, it is unreasonable to expect that the level of cost shifting that will occur as a result of the Buyback Exemption would be at all similar to that experienced under NEM. For the above reasons, the Commission concurs with the ACOS Whitepaper's rationale that the cost-shift resulting from offering a Buyback Exemption will be minimal, as supported by NY-BEST, the City, and AEEI.

Fourth, the Commission must consider whether the Buyback Exemption is consistent with current policy direction and past Commission precedent. As noted by multiple stakeholders, advancing the energy storage market is clearly in the public interest, especially in light of the updated 2030 energy storage deployment goal. As previously discussed, Buyback Service Contract Demand Charges rates do have an impact on stand-alone energy storage systems' economics, both at the Distribution level and at the Wholesale level. Therefore, exempting stand-alone energy storage from Buyback Service Contract Demand Charges would both facilitate such systems' participation in the wholesale markets, as well as provide an incentive to further advance the energy storage market.

The JU argue that a better and more transparent strategy for offering incentives to the stand-alone storage market segment would be to direct the utilities or NYSERDA to implement a new incentive program or enhance existing programs. While the JU is correct that a new program may be more transparent with regard to potential cost impacts on a forecast basis, the same level of transparency can be provided after the fact with rigorous reporting requirements. What the JU ignores, however, is that a new or expanded program is only effective at accelerating the market while developers are confident that their projects will be able to access such funds. A limited exemption to the Buyback Service Contract Demand Charge offers a more stable and predictable incentive that developers can more readily rely on as they seek financing for their projects. Further, the Commission has a long history of support for technology-specific exemptions to various Standby and Buyback Service and associated rate components. Therefore, the Commission finds that offering an exemption from Buyback Service Contract Demand charges to stand-alone energy storage customers is consistent with Commission precedent and is in the public interest.

As discussed above, the Commission finds that, while Buyback Service Contract Demand Charges do impact stand-alone energy storage ability to participate in key wholesale markets, that acceleration of the stand-alone energy storage market segment would be beneficial for grid operations and meeting New York's energy policy goals. Moreover, the impacts of cost shifts caused by offering an exemption to such charges would be reasonable and controllable, and according an exemption to such charges is consistent with both New York's current energy policy direction as well as past Commission actions to spur other technologies. For all of the above reasons, the Commission finds that it is reasonable to provide a limited exemption from Buyback Service Contract Demand Charges for stand-alone energy storage systems.

The Commission rejects the JU's request not to provide the Buyback Exemption to already-installed stand-alone storage systems. As noted above, the Commission has found that Buyback Service Contract Demand Charges are and have been an impediment for full participation in the wholesale market. Existing stand-alone energy storage systems deserve the same consideration as new systems in decreasing barriers to fully participating in the wholesale markets, and deserve to compete in those markets on the same footing as systems installed following this Order.

The Commission also rejects NY-BEST's request to allow the exemption for units participating in NWA projects. Not extending the Buyback Exemption to customers participating in existing NWA Projects is not discriminatory ratemaking, but instead a rational, practical, and reasonable accommodation to ensure fair treatment for both NWA Project participants and the utility customers who pay for such projects. Although NY-BEST is theoretically correct that a windfall resulting from the Buyback Exemption could be negotiated between the utility and existing NWA project participants, NY-BEST fails to recognize the significant labor and legal expenses of reopening and renegotiating previously executed contracts between utilities and participants. These additional costs represent unnecessary incremental expenses that utility customers would have to bear for no incremental benefit. NY-BEST also fails to recognize that these customers may also benefit from the impacts of improved cost allocation and the rate design methodology approved herein. Although NWA participants might also participate in the wholesale markets, and arguably enjoy the same level playing field as all of the other stand-alone energy storage not participating in NWA projects, the Commission finds that, on balance, the need to protect customers from unnecessary costs and contractual windfalls exceeds the value of improving market conditions for these NWA participants. These are conditions which these customers knew, or should have known about, at the time they executed contracts with utilities to participate in the NWA projects.

Although the Commission has addressed the threshold issue of whether to offer an exemption, stakeholders suggested numerous modifications to the ACOS Whitepaper’s proposal that warrant consideration, including: 1) the duration of the Buyback Exemption; 2) eligibility deadlines for participating in the Buyback Exemption; and 3) limits and safeguards to ensure that participation and cost-shifts remain at reasonable levels. Regarding the duration of the Buyback Exemption, many stakeholders offered alternatives to the ACOS Whitepaper’s 20-year proposal. Proposals range from the five-year duration submitted by the JU, to 25 years recommended by NineDot, to MGN’s recommendation that the Buyback Exemption not have any defined duration but instead remain in place until the participation stand-alone energy storage system is decommissioned. There are two main decision points during the life of an energy storage unit: first, an initial decision to build and install the energy storage unit, and second a decision on whether to repower the energy storage unit once its primary cells have degraded but while other parts of the installation still have significant useful life remaining.

The Commission considers the first decision point (i.e., the decision to build the energy storage system in the first place) to be the decision most in need of short-term support. Therefore, the Buyback Exemption should provide financial support for the initial useful life of the cells, with less regard for developers' repowering decisions to be made after approximately 15 years or more. Therefore, the Commission finds that the JU's proposed five-year exemption to be too short, and the ACOS Whitepaper, NineDot, and MGN's proposed 20-year, 25-year, and indefinite exemption durations, respectively, to be too long. Instead, the Commission will approve a 15-year exemption, beginning at each participating customer's in-service date. As noted by NineDot, energy storage systems will typically require repowering after 15 years. Therefore, a 15-year duration for the Buyback Exemption should ensure that developers decisions to build an energy storage system will be fully supported through its initial cycle, with the decision of whether such systems need additional support for repowering left as a decision to be made at a later point in time based on the facts and conditions that are present then.

Regarding eligibility deadlines, stakeholders submitted several proposed modifications to the ACOS Whitepaper's proposed December 31, 2025 in-service date deadline. The City, MGN, NY-BEST, Soltage, and NineDot each recommend that the Commission extend the in-service date deadline for participating in the Buyback Exemption to December 31, 2030, arguing that the nearer deadline of December 31, 2025, would lead to market uncertainty, boom-or-bust cycles in advance of the deadline, and that only a very limited number of systems which begin construction within the next two years would be able to participate. NineDot further recommends that instead of a deadline based on an energy storage system's in-service date, the deadline should be based either on the date a developer makes a 25 percent deposit toward interconnection costs for a project or the date of an executed interconnection agreement if no deposit is required. Although AEEI took no position on the specific eligibility deadline, it did recommend that the Commission convene a midpoint review process to consider whether continued support is needed beyond December 31, 2025.

The Commission finds the stakeholder comments persuasive regarding 1) the need to provide certainty for developers that their projects will be eligible to participate in the Buyback Exemption through December 31, 2025, and 2) the need to convene a midpoint review process. NineDot's proposed solution of modifying the eligibility deadline to be based on the date of the 25 percent interconnection deposit or executed interconnection agreement is preferable, as this will ensure that customers who have committed to their project before the eligibility deadline will have significant certainty that their project is eligible for the Buyback Exemption. This will address the uncertainty associated with an in-service date deadline, which may be affected by unforeseen and uncontrollable delays in construction. The Commission rejects the JU's request to limit the Buyback Exemption to only the first 50 MW of stand-alone energy storage for the same reasons. Implementing a cap on participation would create significant uncertainty as energy storage developers would not know where their individual projects stand in relation to the MW-installed cap, and may result in a boom-and-bust cycle near the cap as developers are unable to rely on their projects being exempted.

Therefore, in balancing the multiple competing interests of advancing the stand-alone energy storage market through the 2025 interim target, ensuring that the incentive provided by the Buyback Exemption is still needed to meet later storage deployment goals, protecting customers from unintended cost-shifting, and providing an incentive in the format that is most useful to energy storage developers, the Commission finds that the Buyback Exemption shall be available to all stand-alone energy storage customers, including already-existing systems not participating in an NWA contract, that have paid the 25 percent interconnection deposit or signed an interconnection agreement by December 31, 2025. The utilities are directed to include draft tariff language to effectuate the Buyback Exemption as described above as part of their 120-day Compliance Filings.

In addition, the Commission directs Staff to convene a midpoint review process beginning in the fourth quarter of 2024 to determine if there is a need to extend the Buyback Exemption beyond the deadline established herein, and to bring a proposal for Commission consideration if appropriate prior to the established deadline. This combination of a time-limited exemption and midpoint review process will ensure that customers only pay for necessary out-of-market incentives for energy storage systems, and will ensure continuity of incentives beyond December 31, 2025, if warranted, thus avoiding the boom-and-bust cycle that NY-BEST cautions against.

In addition to providing a time-limited exemption and midpoint review process, the Commission will also require rigorous annual reporting requirements akin to the reporting requirements related to the standby rate exemptions last considered by the Commission in May of 2021,[87] as well as require the utilities to immediately report to Staff and the Commission when annual cost-shifts resulting from actual Buyback Exemption participants are forecast to exceed one percent of the applicable service classification's annual revenue requirement.

Instead of attempting to forecast a multi-variate cost shift impact, as attempted by the JU and requested by NYECC, it is reasonable that actual cost shifts be carefully observed and reported on with an established limit to trigger immediate reconsideration of the Buyback Exemption, similar to the cap mechanism requested by UIU. Specifically, the utilities shall annually report: 1) the number of participating customers, totaled and by service classification; 2) the total Buyback Service Contract Demand kW participating, totaled for the whole Company and by service classification; 3) total calculated cost-shift by service classification (calculated as a product of the annual kW participating and the otherwise applicable Buyback Service Contract Demand Charge for that year), and in both absolute dollars and as a percentage of the relevant service classification's annual revenue requirement;[88] and 4) for each participating customer and for each participating energy storage system, in the event that a single customer operates multiple participating systems, (a) the service classification, (b) Buyback Service Contract Demand kW participating, (c) in-service

[87] Case 19-E-0079, Standby Rate Exemptions, Order Continuing Certain Exemptions to Standby Rates (issued May 14, 2021).

[88] Utilities whose rate years do not align with calendar years should report these figures on a weighted average annual basis.

date, and (d) the date which the exemption expires.[89] These annual reports shall be filed in Cases 14-E-0488, 19-E-0079, and 18-E-0130 on July 31 of each year.

4. Incentive Clawback and Other Eligibility Requirements

a. Comments

The ACOS Whitepaper's proposal that customers making use of the Buyback Exemption must forfeit $50/kWh of previously awarded NYSERDA Market Acceleration Bridge Incentive (MABI), referred to as the MABI Clawback, garnered modest support. In its initial comments, MGN expresses its support for the ACOS Whitepaper's proposed treatment of projects with existing Market Acceleration Bridge reservations. In its initial comments, Borrego states that it supports the ACOS Whitepaper's proposal, but recommends certain modifications. Specifically, Borrego recommends that customers with incentive reservations outside of the NYISO Zone J (i.e., New York City), should not be required to forfeit $50/kWh of their incentive reservation as a condition of participating in the Buyback Exemption. Borrego argues that while the economic picture in Zone J has improved or remained consistent since the initial sizing of incentive blocks, capacity prices elsewhere in the state have decreased. Borrego states that they, and other market participants, have made significant investments in energy storage projects within Con Edison's Westchester territory, and if the MABI Clawback is approved projects will not be financeable and may be in jeopardy of being abandoned.

In its initial comments, NY-BEST requests that the Commission reject the ACOS Whitepaper's MABI Clawback. NY-BEST states that most of the projects that received the MABI were not

[89] Personal identifiable information provided responsive to this reporting requirement shall be filed confidentially.

subject to Buyback Service, and contends that this retroactive clawback of incentives for certain projects represents another significant challenge for early mover projects which have already taken on a high degree of risk.

b. Determination

The Commission finds NY-BEST's arguments against implementing the MABI Clawback to be persuasive. It is the Commission's intent to provide adequate support to spur energy storage system penetration in New York. While some MABI recipients may also benefit from the Buyback Exemption and the positive impacts of improved cost allocation and rate design methodology approved herein, the Commission recognizes that the current economic conditions are different now than they were in 2020. In particular, the storage industry faces supply chain distortions and cost pressures, like many other industries. Therefore, the Commission rejects the ACOS Whitepaper recommendation that customers making use of the Buyback Exemption forfeit $50/kWh in previously awarded MABI funding.

CONCLUSION

The adoption of the ACOS approach described in this Order will result in Standby Service and Buyback Service rates that more accurately align individual customers' contribution to system costs with the rates such customers pay, thereby sending improved price signals to those customers. Customers opting into the voluntary Standby Service rates will have an increased ability to manage their bills and those bills will more accurately reflect the effects of those customers' usage, specifically when combined with the installation of DERs and electrification technologies. In addition, the adoption of the limited exemption from Buyback rates for standalone energy storage systems will help to further develop and grow the energy storage market in New York that will be necessary to enable the State’s clean energy goals.

The Commission orders:

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 file Allocated Cost of Service studies (ACOS studies) using the Decision Tree methodology, as discussed in the body of this Order, 120 days after the effective date of this Order.

2. The Allocated Cost of Service studies required in Ordering Clause No. 1 shall: 1) apply the full Decision Tree to the costs relevant to the voltage that a customer class interconnects to, and the Higher Voltage Decision Tree for all costs at voltage levels above that which the customer class interconnects to, as shown in Appendix B of this Order; 2) set the customer charge for Standby and Buyback Service customers equivalent to the Customer charge of the applicable parent service classification; 3) define Local costs as those incurred to serve the maximum demand of small groups of up to 10 residential customers, and for individual customers for larger customer types; and 4) consider the typical usage for each type of distribution equipment, as discussed in the body of this Order.

3. New York State Electric and Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas & Electric Corporation shall file the Allocated Cost of Service studies required in Ordering Clause No. 1 on a

Federal Energy Regulatory Commission Account basis, as discussed in the body of this Order.

4. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc. shall file the Allocated Cost of Service studies required in Ordering Clause No. 1 on a Functionalized Revenue Requirement basis, as discussed in the body of this Order.

5. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc., shall produce Allocated Cost of Service studies on a Federal Energy Regulatory Commission Account basis, as described in the body of this Order and pursuant to the requirements of Ordering Clause No. 2 as part of their next base rate proceedings, as discussed in the body of this Order.

6. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall file a description of how they will calculate and accrue any differences in collected revenue between existing Standby and Buyback customers billed at the new rates versus the revenues that would have been collected if billed under current rates within 120 days after the effective date of this Order, as discussed in the body of this Order.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall file draft tariff

leaves to effectuate the directives discussed in the body of this Order, within 120 days after the effective date of this Order.

8. The draft tariff leaves required in Ordering Clause No. 7 shall include: 1) draft tariff language to implement the optional five-year phase in for existing customers; 2) draft tariff language to eliminate the Reliability Credit for customers participating in the updated Standby rates, and to implement a phase-out of same if a customer participates in the rate five-year rate phase-in; and 3) draft tariff language implementing the Buyback Service Contract Demand charge exemption for stand-alone energy storage systems for a period of 15 years beginning on such system’s in-service date, for all eligible systems that have made a 25 percent contribution toward their interconnection costs or have signed an interconnection agreement by December 31, 2025, as discussed in the body of this Order.

9. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall include any necessary draft tariff leaves to effectuate the requirements of Ordering Clause No. 6 within the filing required in Ordering Clause No. 7.

10. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall file bill impacts for existing Standby Service customers within 120 days after the

effective date of this Order, as discussed in the body of this Order.

11. 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 a description of whether the mass market optional demand-based rates are designed to be revenue neutral to some or all of the overall applicable service classification, as discussed in the body of this Order.

12. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall file annual reports detailing stand-alone energy storage system participation in the exemption from Buyback Service Contract Demand charges, as discussed in the body of this Order, in Cases 14-E-0488, 19-E-0079, and 18-E-0130 beginning on July 31, 2022, and annually on July 31 of each year thereafter.

13. The annual report required in Ordering Clause No. 12 shall include: 1) the number of participating customers, totaled for the whole company and by service classification; 2) the total Buyback Service Contract Demand kilowatts participating in the Buyback Service Contract Demand charge exemption for stand-alone energy storage systems, totaled for the whole company and by service classification; and 3) the total calculated cost-shift related to the Buyback Service Contract Demand charge exemption by service classification, in both absolute dollars and as a percentage of the relevant

service classification’s annual revenue requirement, as discussed in the body of this Order.

14. The annual report required in Ordering Clause No. 12 shall include, for each customer and energy storage system participating in the Buyback Service Contract Demand charge exemption, service classification, Buyback Service Contract Demand kilowatts exempted, in-service date for the exempted energy storage system, and date after which the exemption expires, as discussed in the body of this Order.

15. The annual report required in Ordering Cluse No. 12 shall be filed on a confidential basis if compliance with Ordering Clauses Nos. 13 and 14 require the submission of personally identifiable information necessitating confidentiality.

16. 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 a report with the Secretary to the Commission whenever annual cost-shifts resulting from Buyback Exemption participants are forecast to exceed one percent of the applicable service classification’s annual revenue requirement, as discussed in the body of this Order.

17. 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 consult with Department of Public Service Staff and affected stakeholders to develop mass market customer bill impact analyses showing the

impacts of adopting different types of distributed energy resources on customer bills under the standard rates versus the Standby rates, as discussed in the body of this Order.

18. The bill impact analyses required by Ordering Clause No. 17 shall demonstrate the impact of solar photovoltaics, stand-alone energy storage, solar photovoltaic plus energy storage, electric vehicle charging, air-source heat pumps, and ground-source heat pumps, as discussed in the body of this Order.

19. 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 report on the status of the bill impact analyses required by Ordering Clause No. 17 by December 31, 2022, as discussed in the body of this Order.

20. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall include a proposal on whether and how to include Standby and Buyback Service customers in a Revenue Decoupling Mechanism, as described in the body of this Order, in their next base rate proceedings.

21. Department of Public Service Staff is directed to convene a midpoint review process beginning in the fourth quarter of 2024 to determine if there is a need to extend eligibility for the Buyback Service Contract Demand charge exemption for stand-alone energy storage systems beyond December 31, 2025.

22. 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.

23. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

APPENDIX A – COMMENT SUMMARY BY PARTY

INITIAL COMMENTS

Advanced Energy Economy Institute, et al.

AEEI state that they overall support Staff's proposed ACOS methodology, but recommend modifications or refinements. AEEI's comments are organized into two sections: general recommendations on the ACOS methodology, and specific proposals regarding application of the decision tree and its component questions.

AEEI makes five general recommendations regarding the ACOS methodology overall. First, AEEI states that inaccurate allocation of shared costs to local could pose a barrier to achieving state policy goals related to energy storage and electric vehicles. AEEI state that the Contract Demand charge, through which costs deemed as local are recovered, acts as a disincentive for any technology to reduce demand, and particularly harms technologies which can inject power. AEEI argue that an inflated Contract Demand Charge which includes shared system costs inaccurately allocated to local could charge customers for their power injections instead of crediting them, and would also diminish the attractiveness of Standby rates as a tool for encouraging electric vehicle fast charging stations.

Second, AEEI recommend that the Commission clarify the definition of local costs as those which are incurred to serve the demand of a single customer, instead of the definition used in Staff's whitepaper which included costs required to serve a small group of customers. Specifically, AEEI notes that in its answer to question 3 ("could a decrease in demand result in unused assets?"), Staff used the "small groups of customers" definition in considering this question for residential customers and "a single customer" in considering this question for larger commercial and industrial customers. AEEI states that allowing the ACOS methodology to use "a small group of customers" could allow utilities to allocate a significant amount of shared assets as local, and creates ambiguity in the definition of "local costs" which would present challenges for implementation and review of utility ACOS studies. AEEI points to Con Edison's comments during the Second Technical Conference, whereby Con Edison indicated that customers connected to an entire network area could be considered a "small group," as evidence of such ambiguity. AEEI notes that the questions in the Decision Tree should be answered accurately for a class of customers instead of seeking to modify the questions in the Decision Tree for certain classes to shape the outcome.

Third, AEEI argues that Con Edison's distribution network costs are inherently shared, and should not be allocated to local. AEEI states that Con Edison's mesh networks are different than most utility radial and loop systems, and as a result, distribution system costs much closer to customers are shared instead of local compared to other system architecture. AEEI requests that the Commission direct Con Edison, and any other utility that makes use of networked distribution systems, to treat any network equipment that serves more than "a specific customer" as a shared cost when performing their ACOS studies. AEEI notes that Con Edison does not currently break out its network versus non-network distribution system costs, and that two solutions to this issue might be: (1) that Con Edison separately identifies network and non-network costs, allocating network costs to the shared cost category; or (2) that Con Edison continue its current categorization of costs, mixed between network and non-network, and allocate such costs between local and shared at Question 5 using Staff's proposed coincident peak to non-coincident peak allocation ratio.

Fourth, AEEI argues that the "minimum system" methodology of setting customer charges used by several utilities, notably Con Edison, should not apply to ACOS studies. AEEI states that the minimum system method allows for some costs that serve customer demand to be allocated to the customer charge, and therefore that a sizeable percentage of demand-related costs may be allocated to the customer charge before the ACOS methodology is even applied, thereby allowing utilities to bypass the decision tree methodology and allocate a percentage of demand-related costs to local. AEEI notes that it is not aware of any instance where the Commission has specifically endorsed the minimum system method for setting customer charges, and that most recent customer charges set in utility rate cases do not reflect the determined minimum system charge and instead reflect a different amount determined through settlement. AEEI requests that the Commission require all utilities to apply the Decision Tree methodology to all demand-related costs, including those that would otherwise be allocated to the customer charge under the minimum system method until such time as the Commission has undertaken review of the minimum system methodology.

Fifth, AEEI recommends that the Commission consider applying the Revenue Decoupling Mechanism (RDM) to all utilities' standby and buyback rates. AEEI notes that the large shifts in the size of Contract Demand and Daily As-Used Demand charges could have an impact on utilities' ability to recover their pre-determined revenue requirements, especially if such changes induce greater investments in DER and other outcomes supportive of New York's energy policy goals. AEEI states that utilities should be allowed to recover their entire revenue requirement, regardless of how rates are set, and therefore that the revenues associated with utility standby and buyback service rates should be trued-up using an RDM. Specifically, AEEI recommends applying the RDM to those revenues generated through the Daily As-Used Demand Charge.

AEEI makes five comments regarding application of the decision tree. First, AEEI recommends that the decision tree should be applied to each customer service classification and each voltage level. AEEI explains that certain questions may be answered differently if considered for each service classification and at each voltage level, for example, between residential customers and large industrial customers. AEEI posits that the same piece of infrastructure, a high tension conductor, would likely be shared if considered from a residential customer's perspective, or potentially devoted to a specific customer from a large general service customer's perspective.

Second, AEEI recommends that a new question that a new question should be added to the decision tree between questions two and three, intended to determine if a cost would be allocated to shared or local if that cost category would be reduced as a result of customer injections of power (Question 2.5). AEEI relies on guidance provided on page 28 of the 2019 Standby Rate Order[90] which states, in relevant part, that "any category of costs that has the potential to be reduced by an injection should not be classified as local." AEEI recommends that Question 2.5 ask, "would an injection of power from a customer have the potential to reduce costs?" AEEI posits that if the answer to Question 2.5 is "yes," the cost category would be allocated 100 percent to the Shared Costs category, whereas inf the answer is "no," then the cost would continue through the Decision Tree to Question 3. AEEI reasons that if a power injection can reduce load on a distribution facility, the distribution facility must be serving the load of other customers as well, and conversely if a power injection that has no potential to reduce costs if there is no other load on the facility for the power injection to offset.

Third, AEEI requests that the Commission clarify that Question 3 should only apply to individual customers instead of including small groups, as discussed above, and also requests a minor wording modification to Question 3 itself. Specifically, AEEI suggests replacing the "could" in Question 3 to read, "would a decrease in demand result in 'unused assets'?" AEEI states that its recommended modification is in line with comments made by Staff's consultant at the first technical conference stating Question 3 should be answered based on the typical uses of the costs in question, instead of as a search for outliers where the question could be answered in the affirmative for unusual cases.

Fourth, AEEI contends that Question 4 should consider all forms of coincident demand when determining if a cost is Local or Shared, recommending that Question 4 should be modified to read, "does an increase in any form of coincident demand, including demand coincident with system or locational peaks, increase the costs?" AEEI argues there are other significant and cost-relevant coincident demands than just the overall-system coincident demand, for example, the coincident demand of a customer class, or area within the distribution system, which can drive distribution system costs. AEEI further argues that demand can only be coincident if a distribution facility is serving more than one customer's demand, and that any such coincident demands should be considered a driver of Shared costs. AEEI notes that Con Edison's CSRP load relief zones, only some of which are coincident with Con Edison's system-wide peak, are evidence that customers' coincidence with each other within a particular area is often more important for driving distribution costs, and also points to Con Edison's Rider Q Standby Rate design Pilot, which has Daily As-Used Demand Charges which have varying super-peak periods depending on which Network a customer is located in.

Finally, AEEI recommends that the Commission clarify Question 5 to require that the question specify that it would consider individual customers' non-coincident peak demands instead of the non-coincident peak demands of the entire service classification. Specifically, AEEI suggests that Question 5 be modified to read, "does an increase in a specific customer's non-coincident peak demand increase the costs?" AEEI argues that if Question 5 were allowed to be answered from the based on the aggregated non-coincident demand of an entire service classification several categories of costs that only serve large numbers of customers, such as substations, could be party allocated to the Local category. AEEI argues that the impact of the aggregate demand of so many customers does not appear appropriate for testing whether a cost is primarily incurred to serve a single customer. Related to Question 5, AEEI also notes that it agrees with Staff's proposed ratio of coincident peak to non-coincident peak as a reasonable allocator for splitting costs between Shared and Local categories for costs which are determined to be neither fully Shared nor fully Local.

<u>Borrego</u>

Borrego state their strong support of Staff's proposed methodology recommendations. Borrego contends that the existing buyback rates send a fundamentally flawed market signal to participants by charging excessively high fees to energy storage systems that would otherwise provide load relief when needed the most. Borrego maintains that exempting standalone energy storage projects from contract demand charges to avoid adverse outcomes will improve project economics and enable NYC to become an unsubsidized market for these resources within the next few years. Borrego recommends that the Commission adopt the Whitepaper's recommendation to exempt standalone energy storage from contract demand charges under buyback service.

Borrego agrees with Staff's assertion that the JU did not sufficiently meet the Commissions directive to apply a consistent ACOS methodology in the 2019 Standby Rate Order. Borrego recommends that the Commission should direct each utility to fully adopt the Decision Tree Methodology proposed in the Whitepaper.

Borrego expressed concerns over Con Ed's mesh network and the challenges presented in implementing the Decision Tree Methodology. Borrego contends that Con Ed's classification of their mesh network equipment as "Local" based on the definition in the 2019 Standby Rate Order is a misinterpretation. Borrego recommends that the Commission clarify that "a small group of customers" is not meant to describe hundreds of thousands of customers on Con Ed's mesh networks, and recommends that the Commission provide guidance to Con Ed for the treatment of its mesh network in order to facilitate compliance with the Commission's directive.

Borrego supports the proposed legacy treatment of projects with existing Market Acceleration Bridge reservations with one exception. Borrego contends that projects with incentive reservations outside of Zone J (NYC) should not be required to forfeit $50/kWh of their incentive reservation. Borrego argues that the economic picture in Zone J has improved or remained consistent since the initial sizing of incentive blocks, capacity prices elsewhere in the state have decreased. Borrego states that they, and other market participants, have made significant investments in energy storage projects within the Con Ed Westchester territory, and if a clawback is approved, projects will not be financeable and will be in jeopardy of being abandoned. Recommends that the Commission approve the $50/kWh forfeit for Zone J only.

City of New York

The City of New York (City) discusses three general themes in its comments. First, the City notes that supports Staff's proposed ACOS Methodology because it is designed to achieve more uniform, fair, and transparent Standby and Buyback Service rates across the State, and that application of such methodology throughout the State will eliminate much of the variation among the utilities' Standby and Buyback Service rates. The City states that the Decision Tree supports fairer rates that adhere to the principles of cost causation, citing significant movement of Substation and Primary Demand costs from Local into Shared between iterations of Con Edison's ACOS results from those developed prior to the Whitepaper to those presented at the second Technical Conference. The City notes that the proposed ACOS Methodology provides greater transparency, as customers will be better able to track the costs that are driving the rates that they must pay, and that the ACOS Methodology facilitates rate comparisons across the different utilities.

Second, the City recommends that the Commission reject Con Edison and the rest of the Joint Utilities' proposals discussed at the Second Technical Conference, predominantly on the basis that, in the City's view, the utilities did not adequately explain the rationale underlying such modifications to Staff's proposed ACOS methodology or quantify the impacts such modifications would have relative to Staff's proposed methodology. In particular, the City notes that Con Edison and the Joint Utilities advocated for, but did not provide adequate support for, their proposals: (1) to implement the ACOS Methodology using functionalized revenue requirements instead of on a FERC Account basis; (2) to allocate General costs to the Customer, Shared, and Local categories outside the Decision Tree process using the results of the underlying ECOS studies; (3) application of the ACOS Methodology to each customer service classification; and (4) using a different allocation factor for splitting costs between Shared and Local categories where a cost could not be determined to be entirely one or the other. The City expresses particular concern regarding the Joint Utilities' revised allocation factor, which would likely result in greater allocations of costs to the Local category due to the substitution of Individual Customer Maximum Demand in place of a service classification's Non-Coincident Peak. The City requests that the Commission reject Con Edison and the Joint Utilities' proposed modification on the basis that they have failed to demonstrate why such changes should be made, and further requested that if the Commission requires Con Edison and the Joint Utilities to provide additional information stakeholders should be given to provide further comments.

Finally, the City notes that it supports Staff's recommended Buyback Service Contract Demand Charge exemption for stand-alone energy storage projects, but recommends that the Commission extend the in-service date deadline to December 31, 2030. The City notes that the proposed exemption is a beneficial effort that will encourage deployment of energy storage systems, and that such systems will play a critical role in achieving the City and State's policy goals, as well as the requirements of the Climate Leadership and Community Protection Act (CLCPA). The City notes the importance of rapidly increasing energy storage system deployment, and states that the proposed exemption is rational considering the benefits provided to the system by energy storage. The City, however, notes that the under the existing in-service deadline proposed by Staff, this exemption would only be available to energy storage projects that are commenced in the next two years (i.e., by mid-2023). Instead, the City recommends that the Commission extend the in-service date deadline until December 31, 2030. The City states that this longer eligibility period would help provide assurance to energy storage projects seeking to interconnect that the exemption will still be available by the time their project is complete, and that a longer eligibility timeline will allow a greater number of energy storage systems to participate.

Environmental Defense Fund

EDF notes its appreciation for the commitment given by the Commission and Staff to align rates with costs, however – notes that methodologies cannot fully reflect benefits associated with new load and states that adjustments may be required to ensure that market transformation scales up in accordance with greenhouse gas goals. EDF requests that the impact of rates being developed in the VDER proceeding on the adoption and likely charging impact of various types of electric vehicles be given thorough attention.

GlidePath

GlidePath supports Staff’s proposed exemption from buyback contract demand charges, and agrees that if the exemption should be limited, that it is managed on a deadline basis rather than by limiting the number of facilities eligible. GlidePath states that, as the development process is complex, under a quota exemption, it would be difficult to ascertain whether a project under development would reach the applicable milestone before other facilities. GlidePath contends that the cutoff for eligibility be clear, and under the reasonable control of the developer in order to allow developers to confidently invest in advancing projects.

GlidePath agrees that long-term certainty is necessary for development of storage and suggests that other measures to provide certainty be introduced. Glidepath suggests that fixing the Standby Service rates for standalone storage for a similar period or introducing a cap on the increases that projects can be subject to would encourage pro-storage outcomes.

GlidePath notes that raising demand charges would lead to increased prices which storage needs to bin in in order to recover investment, making storage no longer competitive with conventional natural gas and oil resources. In contrast, GlidePath contends, lowering demand charges would allow storage to bid lower wholesale rates and push out fossil fuel energy resources. GlidePath supports minimizing demand charges to the extent possible, even beyond the proposed exemption from Buyback Service charges, to further the development of storage, advance the State's goals, and reduce the total cost to end users.

MicroGrid Networks

MGN states that it generally supports Staff's recommendations in the ACOS Whitepaper, particularly the proposal to exempt stand-alone energy storage projects from Buyback Service Contract Demand Charges in the near term. MGN, however, argues that Staff's proposed in service deadline to qualify for exemption to Buyback Service Contract Demand Charges is insufficient to support a long-term and robust pipeline of energy storage projects. MGN states that interconnecting energy storage projects in the Con Edison service territory takes up to 18 to 24 months, which results in a short ramp-up window to meet the proposed 2025 deadline. Instead, MGN requests that the Commission extend the proposed in-service date deadline of at least December 31, 2027, or preferably December 31, 2030. MGN further states that it agrees with Staff's proposed application of this exemption to previously-constructed stand-alone energy storage projects, subject to the surrender of a portion of the NYSERDA Market Acceleration Bridge Incentive.

In addition, MGN makes a number of other recommendations related to the energy storage systems, Standby rates, and Staff's proposed Buyback Service Contact Demand Charge exemption. First, in addition to Staff's proposal that stand-alone energy storage systems be exempt from Buyback Service Contract Demand Charges, MGN proposes that stand-alone energy storage systems should be completely exempt from Standby Service and Buyback Service. MGN argues that the charges imposed on energy storage system operators for transport and delivery of electricity should reflect market costs at the time of charging[91]. MGN posits that energy injected into the distribution system at times when it is of highest value should neither be subjected to the same rate treatments as load nor subjected to demand charges to deliver it to the utility.[92] MGN states that implementing Staff's proposal would cause energy storage customers whom export more than they withdraw to have to pay one Customer Charge under Standby Service and another

[91] Customers are charged the market price for withdrawals from the system through the Supply Charge.

[92] Grid injections under Buyback Service are already treated separately from withdrawals from the grid under Standby Service. For example, Standby Service customers must pay a Customer Charge, a Contract Demand Charge, and a Daily As-Used Demand Charge, whereas Buyback Service customers, assuming they are also Standby Service customers, are charged only a Contract Demand Charge on the increment of maximum export kW that is greater than the Contract Demand kW determined for Standby Service.

Customer Charge under Buyback Service.[93] MGN notes that energy storage units co-located with distributed solar systems are exempted from both Standby Service and Buyback Service, and argues that stand-alone energy storage resources should not be treated differently.[94] Further, MGN states that distributed energy storage resources located on a utility distribution system are dispatched by the utility to relieve congestion and improve reliability,[95] therefore it is unreasonable to charge the owner of such resource to inject energy needed by the utility perform these services.[96]

Second, MGN requests that the Commission not limit the proposed exemption to Buyback Service Contract Demand Charges for stand-alone energy storage systems to 20 years, as recommended by Staff. MGN notes that a large portion of capital costs associated with the energy storage system, such as land, foundational infrastructure, and interconnection facilities, have useful lifetimes in excess of 40 years, and that an energy storage system can be repowered to extend its useful lifetime beyond 20 years. MGN recommends that the Commission should not limit the proposed exemption to 20 years, but allow the

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[93] Buyback Service customers are only charged a Customer Charge in the event they are not also Standby Service customers. A customer that takes service under both Standby Service and Buyback Service is only required to pay the Customer Charge applicable to Standby Service.

[94] Public Service Law §66(j), et al., exempt distributed solar resources, among others from Standby and Buyback Service.

[95] Contrary to MGN's assertion, not all energy storage resources located on the utility distribution system are dispatched by the utility.

[96] Where an energy storage resource is owned and operated by the utility solely for provision of electric service to customers, such a system receives the same regulatory treatment as other pieces of utility plant, and is not subject to distribution charges.

exemption to remain in place until the participating systems are required to be decommissioned, either by contract or due to degradation of the components. MGN argues, again, that since co-located energy storage systems are exempt from Standby and Buyback Service, there should not be a defined time limit on the proposed exemption on Buyback Service Contract Demand Charges.

Multiple Intervenors

Multiple Intervenors are generally supportive of the standby rate methodology as modified by Staff in the Whitepaper, but note concerns that some existing standby customers could be harmed by the potential change in standby rate methodology. MI state that impact analyses prepared earlier in the proceeding by NYSEG, National Grid, and RG&E indicated that adoption of the then-proposed Standby rates would have detrimental impact on a limited number of standby customers.

MI states that instead of taking service under the new Standby rates, existing customers should be accorded an option to continue service under existing Standby rates, subject to periodic adjustment, referred to as vintaging.[97] MI contend that such a vintaging option is warranted for a number of reasons, including: 1) in some circumstances the new Standby rates could result in significant detrimental rate impacts to customers; 2) the timing of the rate impacts during a global pandemic and economic recession is bad; 3) the Standby rates under consideration are dramatically different from those currently in effect; 4) all, or most, current standby rate customers have presumably relied on the current standby rate methodology that has been in effect for decades; 5) there is little that an existing standby customer can do in response to proposed changes in Standby rates, and; 6) vintaging has been frequently employed

[97] Vintaging is also colloquially known as “grandfathering.”

throughout this proceeding. For these reasons, MI recommend that a grandfathering option be considered.

MI support Reliability Credits as a means of rewarding customers who reliably reduce load below the contract demand during the summer period; however, note that the new Standby rates may eliminate or reduce those credits for certain customers, thereby undermining their intent, and potentially resulting in detrimental rate impacts for certain customers. MI notes that for many large non-residential customers, the proposed Standby rates would, appropriately, either reduce or eliminate Contract Demand Charges by shifting Contract Demand Charges to Daily As-Used Demand Charges, no similar adjustment has been proposed for the applicability of Reliability Credits.

MI recommends that alternative approach is needed to preserve such credits (for example a limited avoidance of Super-Peak Daily As-Used Demand Charges), and propose those customers should be accorded a limited exception to the applicability of Daily As-Used Demand Charges during Super-Peak periods.

NY-BEST

NY-BEST submitted comments centered around three topics: modifications and clarifications to Staff’s recommended Decision Tree methodology, recommendations related to Con Edison’s application of the ACOS Methodology as presented during the Second Technical Conference, and Buyback Service-related recommendations. NY-BEST identifies that a common theme throughout its comments is request that the Commission should provide further clarity upfront in its determinations to help achieve consistency in the statewide approach to developing Standby and Buyback Service rates, and to avoid confusion, uncertainty, and more work in the future in reviewing and implementing each utility’s rates.

NY-BEST states that it generally supports Staff’s recommended Decision Tree methodology, and that such methodology provides much-needed guidance for apportionment of revenue requirements into the Customer, Shared, and Local cost categories. In particular, NY-BEST notes its support for Staff’s proposed ratio of Coincident Peak demand to Non-Coincident Peak demand allocation method for apportioning costs between Shared and Local categories following Question 5 when a cost cannot be determined to be either entirely Shared or shared Local. Notwithstanding NY-BEST’s general support, it does recommend five specific modifications to the wording of the Decision Tree questions, as well as more general recommendations to help ensure a consistent approach statewide. First, NY-BEST recommends adding a new question after Question 2 and before Question 3 (Question 2.5) – “Does a power injection have the potential to reduce the cost of the asset?” NY-BEST proposes that if the answer to Question 2.5 is “yes,” then the cost would be entirely allocated to the Shared category, whereas if the answer is “no,” then the cost would proceed to Question 3 for further determination. NY-BEST posits that adding Question 2A is necessary to align the Decision Tree methodology with the 2019 Standby Rate Order which stated that “any category of costs that has the potential to be reduced by an injection should not be classified as local.”

Second, NY-BEST recommends modifying Question 3 to read, “would a decrease in demand result in ‘an entirely unused asset’?” In its modifications to Question 3, NY-BEST proposes to replace “could” with “would” and add the word “entirely.” NY-BEST argues that “could” needs to be replaced with “would” to reduce the chances of an outlier scenario dictating the answer to Question 3. Instead, NY-BEST posits the most common outcome for a given question for a cost should determine the answer.

NY-BEST also argues that "entirely" needs to be added to Question 3 since nearly all assets are partially unused a portion of the time. NY-BEST clarifies that if an asset is entirely unused due to the disappearance of a single customer's load, then such asset would become a stranded investment and should be allocated to the Local category.

Third, NY-BEST seeks to strike the inclusion of "small groups of customers" from the ACOS Whitepaper's description of Question 3. NY-BEST notes that the Commission has previously defined local costs as those related to "a specific customer," and argues that there is nothing in the record of this proceeding to justify overturning the Commission's previously-identified definition of local costs. NY-BEST further notes that Staff's comments at the First Technical Conference made clear that the "single customer" definition of Local costs was intended to be applied for larger Commercial and Industrial service classifications. NY-BEST, therefore, requests that, at a minimum, consideration of "a small group of customers" should be struck from application of the Decision Tree for Commercial and Industrial service classifications. Regarding Residential service classifications, NY-BEST notes that it supports AEEI's recommendation that the "small group of customers" consideration should similarly not apply. However, if the Commission decides to allow consideration of "a small group of customers" for determining Residential service classification costs, NY-BEST recommends that the Commission should provide clear guidelines on the necessary conditions for using "a small group of customers" instead if "a specific customer" in answering Question 3.

Fourth, NY-BEST recommends adding "or regional peak" such that Question 4 would read, "does an increase in system coincident or regional peak demand increase the costs?" NY-BEST notes that shared infrastructure is needed to support both system-coincident peaks and peaks in regions where regional peak demand may be offset from the systemwide coincident peak load. NY-BEST points to Con Edison's CSRP zones as evidence that regional peak demands may not be coincident with the systemwide peak, and that the presence of these time-shifted regional peaks should not change the logic behind apportionment of costs to Shared and Local categories. As an example, NY-BEST posits that all substation costs should be designated as Shared, even if some of those substations experience peak conditions that are not fully synchronous with the system coincident peak.

Fifth, NY-BEST recommends adding the words "specific customer" to Question 4, such that it reads "does an increase in specific customer non-coincident demand increase the costs?" NY-BEST states that this clarification is necessary to make it clear that the question should apply to assets that serve individual customer peaks, and not non-coincident peak demands for an entire service classification.

In addition to specific wording changes for Decision Tree questions, NY-BEST requests that the Commission reconsider some of Staff's proposed answers to certain questions in the workpapers provided supporting the Whitepaper.[98] First, NY-BEST notes that at the Secondary Demand level Staff answered "yes" to Question 4 ("Does an increase in system coincident peak demand increase the costs?") for Land/Land Rights and Structures & Improvements, but "no" for Conductors. NY-BEST states that the logic behind these answers is unclear, as it would seem that conductors would be subject to cost pressures from coincident

[98] The answers to Decision Tree Questions in the workpapers supporting the Whitepaper were intended to only be indicative and are ultimately moot since it is the utilities, not Staff, that will develop ACOS studies. Stakeholders will be afforded the opportunity to review the resulting ACOS studies.

peaks demand at the secondary voltage level. Second, NY-BEST notes that Staff answered "yes" to Question 6 ("Could a kW of reverse power flow increase the costs?") for Poles, Towers, and Fixtures, and Underground Conduits, and contends that the answer should be "no" since these cost categories are seemingly unaffected by reverse power flows.

In its final recommendation regarding Staff's proposed ACOS Methodology, NY-BEST recommends that the Commission provide additional guidance upfront prior to the utilities each applying the ACOS Methodology. Specifically, NY-BEST requests that the Commission include a memo from Staff providing additional detail and justification behind the logic of its answers to the Decision Tree questions as an appendix to this Order. NY-BEST notes that the ACOS Methodology demonstrates the ability to perform side-by-side comparisons of the various utility examples that Staff included in the ACOS Whitepaper and arrive at a transparent and uniform approach across utilities, but also noted that further Commission guidance is needed to ensure that the ACOS studies remain consistent from utility to utility.

NY-BEST notes that it also reviewed Con Edison's workpapers as presented during the Second Technical Conference, and notes that there are several areas where Con Edison's application of the ACOS Methodology differs significantly from Staff's proposed Decision Tree methodology and conflicts with guidance provided in the ACOS Whitepaper. NY-BEST also notes that it has the same concerns with the other utilities which developed their ACOS results based at the functionalized revenue requirement level instead of on a FERC Account basis, that is, O&R and Central Hudson. While NY-BEST notes that Con Edison's method could be workable after applying several modifications, the Commission will need to determine how important uniformity among utilities is for the ACOS Methodology as an ACOS study performed using the functionalized revenue requirement basis as proposed by Con Edison will be significantly different than one performed on a FERC Account basis as recommended by Staff.

First, NY-BEST contends that Con Edison's method does not allow for Question 6 to be answered at all voltage levels. NY-BEST notes that the purpose of Question 6 is to ensure that Buyback Service charges only reflect costs for assets that are impacted by reverse power flows, and that Buyback Service rates would be artificially inflated if they include costs unrelated to reverse power flows. NY-BEST requests that the Commission direct Con Edison to identify asset categories which might answer "yes" to Question 6, and that Con Edison propose a method for isolating such costs from the larger category groupings.

Second, NY-BEST calls into question Con Edison's rationale behind its answer of "yes" to Question 5 for Substation costs. NY-BEST alleges that Con Edison's answer relies on an edge case scenario – a single extremely customer whose NCP demand drives an increase to Substation costs. NY-BEST posits that Con Edison's answer to Question 5 for Substation costs should be "yes," and that all Substation costs should be entirely Shared instead of apportioned between Shared and Local.

Third, NY-BEST states that both Con Edison's Overhead Lines and Underground Lines costs appear to have been mischaracterized at the Secondary voltage level. NY-BEST notes that Con Edison's answers to Questions 3 through 5 result in all Overhead and Underground Lines categorized as Local costs. NY-BEST contends that these categories of Lines - inclusive of Poles, Towers, and Fixtures, and Underground Conduits - are too broad of an asset to be stranded by a decrease in demand from a specific customer, and that instead Questions 3 through 5 should be answered such that the Overhead Lines and Underground Lines categories are apportioned between Shared and Local.

NY-BEST's final observation regarding Con Edison's application of the ACOS Methodology is that Con Edison did not differentiate between mesh network and radial system costs. NY-BEST notes that the architecture of mesh networks suggests that they have an inherently shared in greater proportion compared to radial networks. Instead, NY-BEST recommends that the Commission direct Con Edison to differentiate overhead assets (i.e., those assets used in radial areas) and underground assets (i.e., those assets used in network areas) by the percentage of the underground assets that belong to mesh networks.

NY-BEST's comments regarding Buyback Service center around three topics. First, NY-BEST notes that it strongly supports the ACOS Whitepaper's proposed exemption from Buyback Service Contract Demand Charges for standalone energy storage systems, however, NY-BEST further notes that because energy storage project development cycles are often two years or more, Staff's proposed in-service date deadline of December 31, 2025, as proposed by Staff, may have the result in a boom-or-bust cycle of rapid early development that grinds to a halt in early 2024. Following on Staff's rationale that the costs of providing an exemption to Buyback Service Contract Demand Charges would be far outweighed by the benefits unlocked by offering such exemption, NY-BEST also argues that Buyback Service Contract Demand Charges should not be imposed on customers at all. NY-BEST states that DER with the ability to export to the grid are required to go through an interconnection study and potentially pay for required upgrades to the system to allow such injections, therefore, injections that drive material costs to the grid or those than can be damaging should be fully addressed in the interconnection study process and associated upgrades. NY-BEST states that New York is the only state to authorize Buyback Service charges related to injections to the grid that exceed Standby Service demands, and further argues that such charges are an unnecessary hurdle to energy storage development. NY-BEST recommends that if the Commission decides to approve a limited exemption it should extend the in-service date deadline through 2030 instead of Staff's proposed December 31, 2025 deadline.

Second, NY-BEST disagrees with Staff's proposal to "claw back" $50 per kWh of incentive awards provided by NYSERDA through the Market Acceleration Bridge Incentive for projects to qualify for the Buyback Service Contract Demand Charge exemption, as well as Staff's recommendation that existing NWA Projects not be eligible for such exemption. NY-BEST notes that most of the projects that received the MABI were not subject to Buyback Service, and contends that this retroactive clawback of incentives for certain projects represents another significant challenge for early mover projects which have already taken on a high degree of risk. NY-BEST alleges that Staff's proposal that existing energy storage projects participating in an NWA Project is discriminatory ratemaking, and that any windfall realized by an NWA project developer should be subject to negotiation between the NWA Project contract counterparties.

Third, NY-BEST provides insight into the intersection between Buyback Service rates and Wholesale Market participation, as requested in the ACOS Whitepaper. NY-BEST states that it is familiar with Con Edison's Wholesale Distribution Service (WDS) Rate O, and, while it is not directly familiar with other utilities' WDS rates, expects that other utilities' WDS rates are developed in a similar manner to Con Edison's Rate O. NY-BEST states that Con Edison's Rate O is derived from that Company's Buyback Service rates, and that Con

Edison has successfully persuaded the Federal Energy Regulatory Commission (FERC) to accept such rate in deference to the New York Commission's determination that the Standby Service rates were just and reasonable. NY-BEST posits that when the utilities make WDS filings before the FERC those filings will be either identical or extremely similar to the Commission-approved Buyback Service rates, and therefore the outcome of this proceeding has major implications of energy storage systems to provide services to the Wholesale Market. NY-BEST further argues that Buyback Service charges pose a barrier for energy storage systems to response to market prices, resulting in an economic cap on the amount of capacity an energy storage resource can provide in capacity markets, and limiting energy storage systems' ability to fully participate in reserve markets. NY-BEST argues that the penalties related to energy storage systems exceeding their Contract Demand kW amounts preclude energy storage systems from fully maximizing injection demands regardless of price signals from the wholesale market or during emergency conditions. NY-BEST further argues that Buyback Service demand charges will stymie the NYISO's efforts to reduce reliance on "out of merit" fossil fuel-fired generating stations through its creation of sub-zonal reserve pockets with NYISO Zone J.

NYECC

NYECC agrees with Staff to base the development of proposed rates under an ACOS model, and agree that the goal of the process is to produce a relatively consistent approach across utilities. NYECC supports Staff's proposed Decision Tree Methodology, noting that the proposed methodology should eliminate as much utility discretion as possible, thus ensuring uniformity among the utilities.

NYECC contends that that the rules around Contract Demand need to be simplified and recommends that the existing standby reliability credit be maintained as it currently exists or be increased until the Commission determines an appropriate objective metric to employ. NYECC recommends that a customer's Contract Demand should be updated every two years, thus removing the "fixed" aspect to this rate component and would encourage customers to keep their historic peak low.[99]

NYECC supports, in the near term, an exemption for a Buyback Service Contract Demand Charge for energy storage systems exporting electricity to the electric grid. However, NYECC notes that the bill impacts on other customers for this exemption need to be transparently provided to ascertain the duration of such an exemption in the long term.

Soltage

Soltage notes that it strongly supports Staff's recommendations in the ACOS Whitepaper, particularly the proposal to implement a 20-year exemption from Buyback Contract Demand Charges for stand-alone energy storage systems. Soltage states that there is an especially strong case for exempting stand-alone energy storage systems from Buyback Service Contract Demand Charges, as doing so will allow for robust price incentives for injecting power during the hours when doing so will relieve the grid and reduce delivery costs for all customers. Soltage notes that energy storage projects serve a different purpose than the traditional distributed generation plants for which Standby and Buyback Service rates were initially designed, namely by injecting power into the grid during peak times instead of mainly reducing demand behind

[99] Rules for updating customer Contract Demand kW are outside the scope of this proceeding, and therefore will not be addressed herein.

customer meters and injecting to the grid only when excess power production cannot be consumed on site. Soltage states that Staff's recommended exemption aptly supports stand-alone energy storage projects.

Soltage does, however, request an extension to the in-service date deadline proposed by Staff, arguing that stand-alone energy storage projects often require a longer utility interconnection process. Given the timeline of the interconnection process for stand-alone energy storage systems, Soltage requests that the in-service date deadline be extended to December 31, 2030.

UIU

UIU state that they strongly support standardizing ACOS methodologies among utilities, but are cautious about demand rates being included as an option for mass market customers on a statewide basis at this time. UIU notes that while the 2020 Staff Whitepaper does not include a section on mass market demand rates, such rates were included in the December 29, 2020 Staff workpapers for upstate utilities, and are intended for consideration by the Commission. UIU contends that before mas market demand rates are presented for final review, it is crucial to identify the bill impacts by comparing the current default tariff rates to proposed rates, cost shifts between the range of high-user mass-market customers to low users, and other consequences of adopting a new rate structure for mass market customers statewide. UIU also recommends a sensitivity analysis to understand the degree of cost shift implications due to the combination of policy goals and customer demand rate adoption.

UIU contends there has been no analysis to support Staff's proposal to exempt stand-alone energy storage customers from BuyBack Service Contract Demand Charges. UIU does believe, however, that it is imperative to place a defined maximum cost shift cap on the amount of stand-alone storage customer exemptions.

UIU notes that comments submitted on standby rate design in June 2020 regarding the use of ACOS studies for developing demand rates for mass market customers were not addressed. UIU states those concerns still apply and lists them as: 1) the lack of consistency among the investor-owned utilities in the development of ECOS studies, which output is utilized by the ACOS methodology and recommends the Commission evaluate and standardize ECOS studies on a statewide basis before considering further rate design; 2) additional mass market rate design techniques should be explored and recommends that opt-in mass market rates should be further explored in the Working Group in Matter 17-01277; 3) there is a lack of load research data available to make decisions about rate design and recommends tracking load profiles and other data, and; 4) the definition of which service classes are included when designing revenue neutral rates among the investor-owned utilities is inconsistent across the State and suggests the Commission address this concern before finalizing any new rate design for mass market customers.

Joint Utilities and LIPA

In their comments the Joint Utilities and LIPA (JU) state that they generally support Staff's Decision Tree approach, but recommend a number of modifications. First, the JU note that Whitepaper's proposed Decision Tree methodology requires answers for a series of questions at the FERC Account level, however, three utilities, Con Edison, Central Hudson, and O&R, group FERC Account-level data into functional categories (i.e., functionalized costs) that are then allocated to service classifications as part of their respective ECOS studies. The

JU argue that it is appropriate to use these functionalized costs for ACOS purposes because the functionalized ECOS revenue requirements can be mapped from the aggregated categories back to individual FERC Accounts. The JU request the Commission provide the flexibility to respond to the Decision Tree questions either on a FERC Account basis or using the functionalized revenue requirements, arguing that requiring the utilities that currently use the functionalized revenue requirements to apply the Decision Tree at a FERC Account level would be a major undertaking only to achieve the same end results. The JU recognize that some parties, particularly NY-BEST, argued at the Second Technical Conference that Con Edison's, Central Hudson's, and O&R's ACOS studies based on functionalized revenue requirements should be rejected as not granular enough – the JU disagree, and recommend that the Commission reject such position.

The JU also notes that LIPA does not file cost information on a FERC Account basis, and sets its rate based on a revenue requirements formula that is not direct tied to FERC accounting and includes significant non-accounting costs such as debt service. LIPA similarly requests flexibility to apply the Decision Tree methodology to reflect underlying costs which would otherwise appear in FERC Accounts where available, and use its approved revenue requirements elsewhere.

Second, the JU recommend modifications to the allocation ratio for apportioning costs between Shared and Local for demand-related asset costs. The JU note that the ACOS Whitepaper includes a discussion on the importance of considering load diversity in identifying the use of utility assets, but argues that Staff's proposed allocator, the ratio of CP to NCP demand, does not capture the full diversity of a class of customers. The JU note that according to the United States

Department of Energy's Load Research Manual, diversity is defined as the relationship between CP demand and the sum of individual customer maximum demands (ICMD) within the class. Instead of Staff's proposed CP/NCP allocator, the JU proposes that the Commission either adopt an allocator using the ratio of CP to ICMD, or otherwise adopt the proxy allocator used in Staff's workpapers based on the ratio of the average on-peak demand to average contract demand. The JU posit that average contract demand is equivalent to ICMD, and that the comparison of average on-peak demand, computed as the sum of on-peak Daily As Used Demands, is a better reflection of diversity within a service classification than Staff's proposed allocator.

Third, the JU note that Staff's Decision Tree process would be applied once on an aggregate basis and would apply to all customer classes and voltage level sub-classes, however, the JU recommend that the Decision Tree should be applied separately for the various service classifications and voltage levels. The JU argue that applying the Decision Tree more granularly would better reflect potential differences in customer impacts on electric system components and impacts on equipment closer to customers taking service at higher voltage levels.

Fourth, the JU disagree with Staff's proposed allocation of General costs to the Customer, Shared, and Local categories, and instead recommend a different allocation strategy for General costs. The JU note that their current ECOS studies already functionalize General costs, and that such functionalized costs should be allocated in the same manner as the other functionalized costs – as an example, the JU noted that all General costs functionalized as Transmission in the ECOS study would be considered entirely Shared, consistent with the Decision Tree outcome for Transmission costs. The JU argue that their proposed treatment of General costs would ensure consistency with the utilities' underlying ECOS allocations and allow each utility to use its ECOS study as the starting point in the ACOS Methodology.

Fourth, the JU state that they have reviewed the ACOS Whitepaper's supporting workpapers, and while they agree with Staff's determinations that the Secondary demand costs would largely be considered Local and Transmission costs would be considered Shared, the JU disagree with Staff's determination that Primary voltage demand costs would be entirely Shared. The JU note that this determination stems from Staff's "no" answer to Question 5, and states that they would instead answer Question 5 as "yes." The JU note that the need for and cost of Primary system facilities is driven by local demands, which may or may not occur at the time of the Systemwide peak. The JU state that answering Question 5 as "yes," as they recommend, results in Primary system costs apportioned between Shared and Local.

Fifth, the JU note that application of the ACOS Methodology is likely to produce new Standby rates for each utility, and such new rates will result in different revenues than those which were computed when revenue requirements for each utility were last determined. The JU note that while some utilities already include revenues resulting from customers participating in Standby rates in their respective Revenue Decoupling Mechanisms (RDMs), others do not. The JU posit that changes to the Standby rates and the revenues they are designed to produce will require a true-up mechanism for those utilities that do not have an RDM for the existing service classifications that are required to take Standby Service so that the new rates do not produce either a revenue windfall or shortfall for each affected utility, and further recommend that the treatment of

Standby rates in RDMs should be addressed in each utility's next rate case.

The JU also provided several comments related to stakeholder positions discussed at the First and Second Technical Conferences. As a general theme, the JU state that they disagree with some of the main goals of many of the stakeholders positions, particularly those designed to minimize the Contract Demand Charge. The JU note that they disagree with results-oriented proposals to decrease Contract Demand Charges as such positions are inconsistent with the Commission's recognition that Standby rates are intended to be the most theoretically pure rate designs available for aligning individual customers' contributions to system costs with the rates that such customers pay. The JU posit that artificially reducing the Contract Demand Charge would undermine both the Commission's position on standby rate design, and also reduce the accuracy of price signals and eliminate operational incentives that customers face in response to such rates.

In addition to its general comments regarding stakeholders positions discussed at the First and Second Technical Conferences, the JU provide input related to specific parties proposals. First, the JU disagree with NY-BEST's position at the Second Technical Conference that the Decision Tree methodology should apply to network systems differently than radial systems. The JU assert that while there are differences in design, cost, and reliability between network and radial systems, the answers to Decision Tree questions, particularly Questions 3 through 5, would be the same for both network and radial systems. As an example, the JU state that in a network area, decreases in demand can result in a reduced number of required transformers and primary cable sections.

Second, the JU note that AEEI discussed its recommendation that the Decision Tree methodology should consider different types of aggregate customer demand than just the systemwide coincident demand and pointed to Con Edison's Rider Q Standby Rate Pilot as evidence that certain rates are timed to coincide with local peaks instead of the system-coincident peak. The JU argue that AEEI's rationale, relying on a strict definition of Local costs as those costs undertaken to serve a single customer instead of a group of customers, is incorrect and contrary to the ACOS Whitepaper's recommendations and would guarantee that most costs are classified as Shared regardless of the characteristics of the underlying equipment and costs. The JU further argue Con Edison's Rider Q standby rate pilot should not the basis for a policy change for the allocation Shared and Local costs for all New York State utilities since the Rider Q program was not designed for that purpose and only has seven participants.

Third, the JU comment on remarks made by AEEI and NY-BEST related to modifications to the Decision Tree methodology. The JU note that AEEI relies on Commission language in the 2019 Standby Rate Order - if a cost could be reduced by an injection of power, then such cost should not be considered Local – should not be taken as a generic determination. The JU argue that since Local costs are the costs of facilities needed to support a customer's load in the absence of the customer's generation, whether a customer can inject power does not change the underlying system requirements and related costs designed to meet the customer's needs when it is not injecting power. The JU note that most Standby Service customers with on-site generation do not inject into the system, and that, per the 2019 Standby Rate Order, Standby rates will be available as a rate option for customers regardless of whether they have on-site generation. The JU request that the Commission accord AEEI's proposal with no weight, as they posit that the proposal is not based in fact. The JU also recognize NY-BEST's proposal along similar lines made at the Second Technical Conference to add an additional question to the Decision Tree, "does power injection have the potential to reduce cost for the asset?" The JU similarly request that the Commission reject NY-BEST's proposal, alleging that NY-BEST's proposal would simply advance its interests in minimizing the allocation of costs to the Local category.

Finally, the JU state that they do not support Staff's proposed exemption to Buyback Service Contract Demand Charges for stand-alone energy storage systems and recommend that the Commission reject such approach, or, failing that, that the Commission adopt a more limited exemption. The JU make four arguments in support of their request that the Commission reject the proposed exemption. First, the JU argue that the proposed exemption is contrary to previous Commission directives that Standby and Buyback Service Contract Demand Charges should apply to energy storage systems. The JU state that the Commission has previously rejected this type of exemption because such an exemption would allow projects to avoid being charged an appropriate amount to support existence and maintenance of the electric grid. The JU argue that the Buyback Service Contract Demand Charge provides both an appropriate price signal to size maximum injections and to help the electric distribution utility anticipate power flows.

Second, the JU argue that the Commission should not ignore the potential impacts of granting the proposed exemption on other customers, especially given the 20-year duration of the proposed exemption. Contrary to Staff's claim that the impact of the proposed exemption on other customers would be small, the

JU argue that the impact on customers could be significant. The JU note that there are approximately 300 megawatts of stand-alone energy storage system currently in Con Edison's interconnection queue, and estimates that the impact if even half of those systems participating in the exemption could result approximately $7.5 million in uncollected Buyback Service Contract Demand Charge revenue per year, or about $150 million over the lifetime of the 20-year exemption. The JU further argue Staff's assertion that the increase in stand-alone energy storage projects will be small also ignores lessons learned from similar rate-based programs such as Net Energy Metering, where customer adoption of NEM-eligible technologies rapidly outpaced deployment forecasts and required multiple program cap increases. In addition, the JU expresses concern that Staff's proposal to retroactively apply the exemption to existing stand-alone energy storage facilities would create a windfall for those customers at the expense of others.

Third, the JU argue that Staff's proposed exemption is not the ideal delivery method for providing a technology-specific incentive. The JU posit that New York's experience with Net Energy Metering demonstrates that static exemptions embedded in Commission-approved rates are not an appropriate tool for emerging technologies like storage and renewable generation, and argue that this technology- and use case-specific exemption could hinder the transition to the more advanced technologies as they develop, and that such static incentives embedded into rates cannot adjust quickly enough to meet evolving technological and market changes as they occur. Instead of the exemption, which the JU describes as expensive, inequitable, and opaque, the JU state that it would be a sounder and more transparent policy to explicitly provide incentives to desired technologies which can be periodically reset, for example through a NYSERDA program. The JU suggest that utility or NYSERDA incentive programs should be enhanced if the existing incentives are not sufficient to spur the desired amount of energy storage development.

Fourth, the JU argue that although the ACOS Whitepaper generally stated that energy storage injections are broadly beneficial, it is possible that injections could impose costs on the electric system, instead of reducing costs. The JU state that local infrastructure must be sized to accommodate a customer's maximum demand, whether such maximum demand is related to imports from the grid or exports to it. The JU conclude that a blanket 20-year exemption is likely to impose cost shifts on non-participating customers and lead to an incremental increase in utility costs as level of energy storage adoption increase, as the Buyback Service Contract Demand Charge is a useful tool in encouraging the appropriate sizing and operation of stand-alone energy storage systems. In addition, the JU note that the Whitepaper does not include any proposals on how to ensure that stand-alone energy storage systems are operated in a manner that is beneficial to the grid rather than cost-causative. The JU claim that if energy storage systems export power during periods of low load, such export could lead to curtailment of intermittent renewable resources instead of increasing their hosting capacity. The JU assert that while future dispatch and coordination paradigms may be developed to manage these constraints, in the meantime the Buyback Service Contract Demand Charge should continue to be imposed on stand-alone energy storage systems.

To the extent that the Commission nevertheless determines to provide an exemption from Buyback Service Contract Demand Charges, the JU recommend that such exemption should be limited to the first 50 MW of stand-alone energy storage and only applicable for a five-year duration. The JU argue that an exemption duration of five years is a reasonable amount of time to determine how successful the incentive is at driving energy storage penetration, and to provide for appropriate adjustments going forward. The JU state that the 50 MW capacity limit is aligned with Con Edison's Distributed System Implementation Plan, which is derived accounting for the current trajectory for stand-alone energy storage systems based on the number of MWs of such systems currently in Con Edison's interconnection queue.

Lastly, the JU provide a response to Staff's request for comment on the interaction between charges related to participation in wholesale markets and Standby and Buyback Service charges. The JU state that Buyback Service rates are not generally applicable to wholesale market generators providing energy, ancillary services, and capacity in the wholesale market, however, Standby Service rates do apply to wholesale generators connected to utility systems, including those that take station service from the NYISO. The JU state that Standby Service Contract Demand Charges are unlikely to impact an energy storage system's day-to-day participation in NYISO markets and are unlikely to affect bidding behavior for ancillary or energy services. Although the JU admit that Standby Service Contract Demand Charges could have a modest impact on a market participant's capacity bids, the impact of such charges on the clearing prices of the broader Capacity market are likely to be negligible. The JU argue that since there are minimal impacts on the wholesale market, costs associated with infrastructure that specifically serves a customer should be recovered from that customer.

REPLY COMMENTS

AEEI

In its reply comments, AEEI responds to comments submitted by the JU, as well as to comments submitted by several other parties. In reply to the JU, AEEI first argues that the JU proposal for an alternate allocator for apportioning costs between Shared and Local following Question 5 should be rejected. AEEI notes that it has concerns regarding whether any measure of diversity of demand can accurately determine whether components of a distribution network are Shared or Local since the answer provided by a ratio of different types of demand, as such as those proposed by Staff and the JU, is not affected by the actual use of components or topology of a system. To illustrate its point, AEEI supposes two hypothetical systems, a low-density rural network where each customer must be served by its own feeder and transformer, and a high-density urban area where each feeder and transformer serve multiple customers. AEEI posits that despite significant differences between its two hypothetical networks, costs would be allocated between Shared and Local in the same proportion among the two systems if the customer usage patterns in each system is the same.

AEEI states that while using an allocator based on diversity of demand is reasonable because the alternative, a thorough examination of the specific facilities in questions, is impractical, the JU's proposed allocator, the ratio of CP to ICMD, is the least reasonable allocator of those presented. AEEI argues that using the ICMD as the denominator of such ratio relies on the faulty assumption that all distribution infrastructure is built to the accommodate unrealistic conditions of all customers using electricity at their historical maximum levels simultaneously. AEEI notes that, conversely, the design of distribution systems recognizes that customers will use power at different times, and a customer class’s non-system-coincident demand, or NCP, is a more realistic measure of the maximum demand that individual components of the electric system are designed to accommodate. AEEI states that it endorses Staff’s proposed allocator, the ratio of CP to NCP, and notes that several other parties also agree with Staff.

Second, AEEI agrees with the JU’s proposal to implement a revenue true-up mechanism. AEEI states that the purpose of the ACOS studies is to better align Shared and Local costs allocations with the design of electric distribution systems, not to create utility revenue losses or windfalls. AEEI notes that although it had recommended that the Commission require the utilities to implement Revenue Decoupling Mechanisms to apply to Standby Service, the JU’s proposed true-up mechanism would serve a similar function and allow any issues related to RDMs to be considered in the context of utility rate proceedings.

Third, AEEI disagrees with the JU’s statements that the Decision Tree would produce the same results for both network and radial system designs, and argues that the utilities should distinguish between network and radial areas in applying the ACOS Methodology. AEEI take issue with the JU’s rationale, arguing that the JU on one hand admit that there are differences in the design, cost, and reliability of network and radial systems, and on the other hand ignore that such differences exist because customer load is carried in a different manner over the two types of system. AEEI highlights that because load in a network system is able to flow to customers through multiple pathways, network facilities are fundamentally deployed to serve multiple customers, not just the load of any specific customer. AEEI also takes issue with the description and examples of networks provided in the JU's comments, noting a difference in the use and deployment of spot networks, which are generally deployed to provide additional reliability to a specific customer, and area networks which are deployed to serve multiple customers. AEEI recommends that the Commission require that the utilities apply the Decision Tree in a manner that recognizes the increased amount shared assets closer to the customer in area networks.

Fourth, AEEI requests that Commission reject the JU's arguments against AEEI's recommended modifications to Questions 4 and 5 considering aggregated NCP demand as a driver of Shared costs. AEEI argues that if the system-coincident peak demand is the only coincident demand considered, the aggregate demands of hundreds or thousands of customers could be considered Local costs so long as such demand peaks do not coincide with the systemwide peak, thereby allowing facilities which serve many customers to be considered Local.

Fifth, AEEI, in support of its proposal in its initial comments to add a new question between Questions 2 and 3 (Question 2.5), states that the impact of injected power on system costs is a useful hypothetical for distinguishing between Shared and Local costs. AEEI notes that, while the JU objected to its proposed Question 2.5 on the grounds that most Standby Service customers do not inject power and that Standby rates would be made available to customers without on-site generation as a rate option, its proposed Question 2.5 poses a hypothetical to help determine whether a cost should be allocated to the Shared or Local category by considering whether a hypothetical injection would decrease costs, regardless of whether such injections are likely. AEEI states that considering the effect of power injections is useful to distinguish between Shared and Local costs because injections have an opposite effect on Shared and Local costs. AEEI elaborates that an injection may increase Local costs while decreasing Shared costs, whereas an equivalent consumption from the grid would increase both Shared and Local costs. AEEI also argues that the Commission has previously acknowledged the probative value of considering injections to distinguish between Shared and Local costs in the 2019 Standby Rate Order.

AEEI asserts that entire basis of the JU's arguments against the addition of a Question 2.5, is contrary to past Commission determinations. Specifically, AEEI takes issue with the JU's characterization of Local costs and the impacts of injections on such costs.[100] AEEI states that, contrary to the JU's assertion, it is Standby rates in total, not just the Local costs, which reflect the cost to support a customer's load in the absence of a customer's generation. AEEI also argues that the JU misstates the purpose of Local costs, which AEEI states is to reflect the persistent costs of injected or consumed power, even during times when there are no injections or consumption.

Sixth, AEEI agrees with other stakeholders that the Commission should require Con Edison, Central Hudson, and O&R to file ACOS studies based on the more granular FERC Account data instead of aggregated by Functionalized Revenue Requirement. AEEI argues that using Functionalized Revenue Requirement data sacrifices data granularity for no apparent benefit, while creating greater opportunities for utility judgement and subjectivity, potentially impacting the results of the ACOS study. AEEI notes that its recommendation does not apply to

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[100] "Local costs are costs of the facilities needed to support a customer's load in the absence of the customer's generation. Thus, the fact that the customer injects power is not related to system requirements and underlying costs at times when there are no injections." – JU Comments, p. 11

LIPA which as a state-owned utility accounts for its costs differently than investor-owned utilities, and has the latitude to modify the ACOS methodology implemented for its territory to suit any operational differences it may have from the investor-owned utilities.

Seventh, AEEI notes that it supports the Whitepaper's recommended Buyback Exemption, as near-term relief from Buyback Service Contract Demand Charges are necessary to improve the economics of stand-alone energy storage systems, particularly in downstate utility service territories. AEEI notes that it does not endorse a specific in-service date deadline, but recommends that if the Commission extends such deadline through 2030 a midpoint review process may be warranted to determine if energy storage economics have changed and whether the Buyback Exemption remains necessary.

Finally, AEEI recommends that the Commission provide additional guidance on application of the Decision Tree Methodology to improve consistency among utilities and decrease subjectivity. AEEI states that while the Decision tree is concise, it leaves substantial room for subjective interpretation and application. As evidence of the need for additional guidance, AEEI points to the differences in how the Decision Tree Questions were answered in the Whitepaper compared to how the same questions were answered by the utilities. AEEI states that it endorses the recommendations of NY-BEST in this regard.

<u>City</u>

The City addresses three topics in its reply comments. First, the City agrees with other stakeholders that the Commission should provide additional clarification and guidance on the Decision Tree methodology. The City agrees with other stakeholders that the Decision Tree Methodology should be uniformly applied across all utilities, and that ambiguity and utility discretion in applying the Decision Tree Methodology should be minimized. The City argues that for the Decision Tree Methodology to be a standardized and repeatable process as envisioned by the Whitepaper, the Commission must provide sufficient guidance for the utilities to answer Decision Tree questions, and that absent such guidance the utilities may be afforded too much discretion in deciding how to answer questions. The City highlights the need for further guidance by citing Con Edison’s presentation at the Second Technical Conference, wherein that Company indicated that it proposed to treat entire network areas as a single small group of customers, and that it intended to categorize substation costs as apportioned between Shared and Local, when, in the City’s view, such costs should be categorized as entirely Shared. The City requests that the Commission provide additional clarification to the questions posed by the Decision Tree and provide additional guidance regarding the definition of a small group of customers for use in defining Local costs.

Second, the City requests that the Commission reject the JU alternate allocators for apportioning costs between Shared and Local following an answer of “yes” to Question 5. The City posits that the JU did not provide sufficient substantiation for their argument that the Whitepaper’s proposed allocation ratio of CP/NCP should be rejected because it does not capture the full diversity of a class of customers. Instead, the City argues that the JU have failed to establish that their proposed allocation ratios are more appropriate than that presented in the Whitepaper. The City also notes that the JU’s preferred allocation ratios would have a material impact on the allocation of costs between Shared and Local categories, resulting in costs being shifted out of the Shared category and into the Local category. The City argues that the Whitepaper's CP/NCP allocation ratio generally results in a more appropriate allocation of costs to the Shared category, and therefore that the JU's preferred allocation ratios should be rejected.

Third, the City provides additional support for the Buyback Exemption and its proposed extension of the in-service date, as well as responds to the JU's request that the Commission reject such Exemption. The City states that a longer eligibility period, to December 31, 2030, is necessary to provide energy storage resources with sufficient assurance will still be available by the time their projects are complete. The City argues that unless the in-service date deadline is extended the Buyback Exemption will have limited impact as it may only actually be available to projects that are commenced within the next two years due to energy storage projects' 18-24 month development timeline. The City argues that the Buyback Exemption will remove a significant barrier to growth of stand-alone energy storage projects, and that such projects are critical to achieving the objectives of the CLCPA and other State energy policies. The City contends that the JU's argument that additional support for energy storage projects is not needed is unfounded, since the 2021 State of Storage Report found that the cumulative energy storage projects deployed at the end of 2020 was 1,186 MW, or 70 percent of the 2025 storage penetration goal, and only 40 percent of the 2030 target.

Joint Utilities

The JU offer a preliminary statement providing a central underpinning for each of the substantive responses to stakeholder comments which follow. First and foremost, the JU note that in this proceeding the Commission must determine whether the adoption of the recommendations in the Whitepaper would result in just and reasonable rates for all customers, not just the subset of customers subject to Standby and Buyback Service rates. The JU further note that the Decision Tree Methodology proposed in the Whitepaper would result in Local cost allocations of zero for most of the National Grid, NYSEG, and RG&E customer classes, that such recommendations would eliminate or substantially minimize the Local cost allocations of other customer classes, and that the results would be similar if applied to Con Edison, Central Hudson, and O&R. The JU offer three scenarios whereby the avoidance of customer demand during on-peak periods results in what the JU refer to as "free delivery service" while at the same time the utility must maintain the grid required to reliably provide Standby Service to the customer, potentially resulting in other customers bearing an increased cost. The JU argue that these outcomes which result in a shift of nearly all of a Standby customer's delivery costs to other customers are unreasonable, and unjustifiably favor certain resources' energy usage characteristics over others. In particular, the JU urge the Commission to reject what they characterize as favoritism for stand-alone energy storage.

Following their preliminary statement, the JU address each of the comments provided in stakeholders' initial comments. First, the JU address stakeholder comments regarding use of the Functionalized Revenue Requirements. The JU argue that, contrary to stakeholder positions, using Functionalized Revenue Requirements instead of applying the Decision Tree on a FERC Account basis is appropriate since the FERC Accounts can be mapped to the Functionalized Revenue Requirements, and assert that Con Edison's presentation at the Second Technical Conference demonstrates such. The JU also argue that using Functionalized Revenue Requirements in ACOS studies is consistent with prior Commission direction in this proceeding, citing the description of ACOS studies in the 2019 Standby Rate Order. The JU reiterate their request that the Commission grant the flexibility to implement the Decision Tree based on either a Functionalized Revenue Requirement basis or on a FERC Account basis.

Second, the JU address the City's comments regarding the mixed Shared and Local allocation ratio. The JU assert that the City's argument that the JU had failed to justify its proposed CP/ICMD ratio is misplaced. The JU argues that it fully addressed it position at the Second Technical Conference that the CP/ICMD ratio better reflects diversity within a customer class. The JU also argue that the City's preferred ratio, the CP/NCP ratio proposed in the Whitepaper, is not well supported, alleging that such ratio was based only on a generalization that the ratio of CP to NCP is a proxy for identifying the usage of an asset. In addition, the JU note that the City and NYECC's concern over not having access to the JU presentation and supporting materials expressed in their initial comments is moot since such information is currently available.

Third, the JU reiterate their support provided in their initial comments of allocating General costs to certain functions prior to costs being allocated to Customer, Shared, and Local through the Decision Tree Methodology as is currently established in their ECOS studies. The JU argue that using the ECOS allocations of costs to functions instead of the separate treatment proposed in the Whitepaper is consistent with description of ACOS studies provided in the 2019 Standby Rate Order that the ACOS studies should build upon an existing ECOS study.

Fourth, the JU address stakeholder comments regarding proposed modifications to the Decision Tree Methodology. The JU address NYECC's comments expressing concern over uniformity amongst utilities, noting that each of the utilities answered the Decision Tree Questions in exactly the same way, arguing that the JU's answers already provide the uniformity that NYECC is seeking. Th JU address AEEI and NY-BEST's proposal to add a question between Question 2 and Question 3 (i.e., Question 2.5) by reiterating their arguments on this topic from their initial comments verbatim. Next, the JU argue that AEEI's recommendation that Question 3 rely solely on the definition of Local as costs required to serve a single customer, and NY-BEST's recommendation that the question be modified to consider only an "entirely unused" asset are only attempts to minimize the allocation of costs to the Local category. The JU state that AEEI's argument ignores that certain assets may service a small group of customers, while NY-BEST's argument ignores that a decrease in load by a customer or small group of customers that results in a stranded asset should be considered Local.

Regarding proposed modifications to Question 4, the JU note that both AEEI and NY-BEST request that Question 4 consider more types of demand than just the Coincident Peak, and rely on observations related to Con Edison's CSRP demand response program. The JU note that the network peaks referred to by AEEI and NY-BEST are non-coincident peaks by definition, and it is not reasonable to consider such peaks in Question 4 because non-coincident peaks are specifically addressed in Question 5. The JU assert that AEEI and NY-BEST's comments in this regard represent an attempt to classify more costs as Shared.

Regarding proposed modifications to Question 5, the JU recommend that the Commission reject AEEI and NY-BEST's proposals to consider individual customer non-coincident peaks instead of the customer class non-coincident peak. The JU argue that AEEI and NY-BEST's recommendations are based on an attempt to minimize costs classified as Local by relying solely on costs were incurred to serve a single customer, and notes that the costs examined in the Decision Tree, whether as Functionalized Revenue Requirements or on a FERC Account basis, are considered on an aggregated basis and not intended to identify specific costs for facilities intended to direct serve a single customer.

Regarding NY-BEST's suggestion that pole and underground conduit costs should be excluded from Con Edison's Local cost category for Buyback Service, the JU disagree with NY-BEST's suggestion that reverse power flows do not impact the relevant costs. The JU explain that injections from batteries may in the future impose costs on the delivery system to accommodate novel injections of power, and that there may be injection-related costs for poles, underground conduit, and conductors depending on the magnitude of such injections.

The JU also respond to NY-BEST's commentary on Con Edison's workpapers - specifically NY-BEST's assertions that (1) Con Edison's Functionalized Revenue Requirement method precludes Con Edison from answering Question 6 for all voltage levels; (2) that Con Edison's answer to Question 5 inaccurately apportions substation and other costs between Shared and Local justified by use of an edge case. The JU assert that Con Edison's Functionalized Revenue Requirement has no impact on whether or not Question 6 is answered at every voltage level, and notes that based on the way the Decision Tree is set up, it may not be possible to answer Question 6 for every voltage level regardless of the level of granularity used in the ACOS study.[101] The JU states that Con Edison's answer to Question 5 does not, in fact, rely on any edge cases, since investment in substation and

[101] For example, the Whitepaper's Decision Tree does not require that Question 6 be answered for costs assigned to the Local category as a result of answering "yes" to Question 5.

primary demand facilities is, according to JU, driven by local loads characterized by non-coincident peak demands.

Fifth, the JU responds to AEEI's comments regarding Con Edison's minimum system ECOS methodology. The JU assert that neither of AEEI's concerns, that using the minimum system methodology will allow utilities to bypass the Decision Tree and allocate a portion of demand-related costs to the Local category, and that the Commission has never endorsed the minimum system methodology, are valid. The JU further argues that AEEI's concerns are little more than a results-oriented recommendation to significantly reduce the Contract Demand Charge.

The JU argues, as a threshold matter, that the Commission has directed that the ACOS methodologies are to rely on existing ECOS studies, a position which was also advanced by Staff at a Technical Conference following the 2019 Standby Rate Order but preceding the Whitepaper. Next, the JU point out that Con Edison has used the minimum system methodology for many years, and that the Commission has previously approved the minimum system methodology as part of the litigated phase of Con Edison's 2016 rate proceeding wherein the Commission dismissed challenges to Con Edison's minimum system methodology-based ECOS study.[102] The JU assert that AEEI's argument that the minimum system methodology deserves review before the Commission implements new Standby and Buyback Service rates based on Con Edison's ACOS results is beyond the scope of this proceeding, and, bedsides, stakeholders have reviewed the minimum system methodology as part of Con Edison's 2016 rate proceeding, and the Commission found such result reasonable and in line with

[102] Case 16-E-0060 et al., Consolidated Edison Company of New York - Rates, Order Approving Electric and Gas Rate Plans (issued January 25, 2017) (2017 Con Edison Rate Order).

recommendations provided in the Electric National Association of Regulatory Utility Commissioners Manual on utility cost studies. The JU argues that, in fact, the Commission has specifically addressed issues related to portions of Con Edison's transformer costs being included in the Customer Charge as a result of the minimum system methodology and approved Con Edison's ECOS study.

The JU argue that AEEI's recommendations would result in the Decision Tree inaccurately allocating certain Customer costs to the Shared category. The JU also contend that, contrary to AEEI's arguments, even though Con Edison's customer charge is set at a level less than that identified in its ECOS study, such Customer Charge does indeed reflect the use of the minimum system methodology.

Sixth, the JU respond to comments from AEEI, Borrego, and NY-BEST arguing that the Decision Tree should apply to network systems differently than radial systems. The JU assert that while there are differences in design, cost, and reliability between network and radial systems, the utilities' answers to the Decision Tree Questions would remain the same whether considering a network or radial system costs, since an individual customer's load impacts various network system distribution functions just as it would a radial system. The JU further argue that although decreases in an individual customer's demand would have a more obvious impact on a radial system, reductions in customer demand can result in unused assets in a network system as well. As evidence of their argument, the JU point out that reductions in customer demand can reduce prioritization for open mains replacement projects serving lower demand.[103]

Seventh, the JU respond to comments from MGN, GlidePath, Borrego, the City, NYECC, and NY-BEST, and supporting the Whitepaper's proposed Buyback Exemption for stand-alone energy storage systems and their various proposed modifications to such. The JU reiterate their position that the Commission should reject the Buyback Exemption outright, noting that the proposal contradicts previous Commission determinations that Buyback Service Contract Demand Charges should apply to energy storage and other applicable DER types, and that this type of exemption would allow projects to avoid charges deemed appropriate for supporting the existence of the electrical grid.

The JU also argue that the Whitepaper's Buyback Exemption is contrary to Staff's April 2021 State of Storage Report,[104] suggesting that the Buyback Exemption is unnecessary. The JU point to various passages in State of Storage Report which state that "the portfolio of programs and actions approved by the Commission… has effectively accelerated New York's energy storage market," that the amount of storage already deployed or that have been awarded or contracted amount to 79 percent of the 2025 target and 40 percent toward the 2030 target, and that there are over 8,000 MW of energy storage systems in the NYISO interconnection queue. The JU note that while the State of Storage Report does mention the Whitepaper, it does not discuss

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[103] An open main refers to a secondary voltage distribution cable which has failed due to physical damage to the cable insulation. The JU explains that Con Edison analyzes and prioritizes open mains replacement projects, and following a reduction in demand assigns a lower priority to the affected open mains.

[104] Case 18-E-0130, Storage Proceeding, Second Annual State of Storage Report (submitted April 1, 2021) (State of Storage Report).

the Buyback Exemption in any detail nor offer any justification for such exemption. The JU also note that the State of Storage Report finds that "no corrective actions to the Commission's energy storage deployment policy are necessary at this time."

The JU reiterates its position, multiple times, that it prefers that the Commission approve more explicit and transparent incentives through additional NYSERDA incentives if the Commission determines that more incentives are justified. The JU argue that none of stakeholders which support the Buyback Exemption have adequately explained why an incentive through rate design is needed. The JU point to the growth energy storage systems in utility interconnection queues without the Buyback Exemption, and argue that although they provided a conservative estimate of $150 million in cost-shift impact of the Buyback Exemption, the impact of providing a Buyback Exemption to all energy storage systems needed to achieve the 3 gigawatt (GW) goal by 2030 could be almost $3 billion. The JU state that NY-BEST and Borrego's implicit argument, that absent Commission approval of the Buyback Exemption, the increase in stand-alone energy storage projects is likely to be small and therefore the CLCPA goals cannot be met, ignores robust growth in the storage industry to date, and that the Commission should learn the lessons of past uneconomic DER support.

Eighth, the JU address MGN's request that energy storage systems also be exempted from Standby Service delivery charges based on MGN's argument that such delivery charges represent a double-payment by energy storage customers for the same service and that Standby Service charges are a barrier to energy storage resources competing in the market. The JU urge the Commission to reject MGN's request since it is reasonable for an energy storage system that uses the distribution system to contribute toward the costs of that system, and that mechanisms are in place to resolve any potential over-recovery of distribution charges. Specifically, the JU point to the presence of RDMs, and periodic revisions to billing determinants used in revenue allocation and rate design in future rate proceedings as the vehicle for addressing any over-recoveries of system charges in aggregate.

Ninth, the JU address what they characterize as NY-BEST's request for special treatment for energy storage systems, such as the elimination of the Contract Demand Charge, due to the value of energy storage injections. The JU argue that NY-BEST ignores that while energy storage resources can obtain revenues from participating in wholesale markets and other utility compensation such as NWA projects, to do so such resources must have access to the utility system and the wholesale markets, therefore, without connecting to the distribution system there is no value proposition for energy storage. The JU argue NY-BEST's request as such request would allow energy storage resources to pay virtually nothing to access the distribution system, and treat energy storage resources differently than other similarly-situated customers that inject electricity from other forms of DER.

The JU reiterate their argument from their initial comments, verbatim, that while energy storage resources dispatched by a utility can provide benefits to the distribution, a significant amount of poorly-controlled energy storge resources clustered on a circuit may impose costs on the delivery system and lead to curtailment of renewable resources. The JU argue that the Buyback Service Contract Demand Charge encourages appropriate sizing and dispatch of stand-alone energy storage, and that the elimination of such charge would exacerbate the potential for increased system costs due to injections from energy storage resources at the wrong time.

Tenth, the JU address comments from GlidePath and Borrego which posit that Contract Demand Charges are ultimately neutral to energy storage resources. The JU first address GlidePath's position that energy storage resources participating in the wholesale market would include such costs in their wholesale market bids, thus if energy storage resources are the marginal generator, all customers would, in effect, pay for energy storage resources' Contract Demand Charge costs. The JU contend GlidePath's argument ignores (1) that energy storage resources may not participate in the wholesale markets or set market prices; (2) that Standby Service Contract Demand Charges, which can be reset annually, are unlikely to impact a storage units day-to-day participation in the NYISO energy and ancillary services markets; and (3) that the impact of Contract Demand Charges on capacity prices is likely to be negligible.

Next, the JU address Borrego's argument that Commission approval of the Buyback Exemption would help New York City become an unsubsidized market for energy storage resources, arguing that Borrego's stated rationale for such exemption fails to support its position. The JU point out that existing NYSERDA incentives preclude the energy storage market from being unsubsidized currently. The JU also note that if the Commission were to approve the Buyback Exemption, it would lock in a subsidy for energy storage resources until at least 2045. The JU further note that the need for the Buyback Exemption is lessened if the cost of stand-alone energy storage levels declines to a level where subsidies are no longer needed within the next few years, as forecast by Borrego.

Eleventh, the JU address Borrego's request that energy storage resources outside of NYISO Zone J which take the Buyback Exemption should not forfeit $50/kWh of NYSERDA MABI funding. The JU note that Borrego's position is dependent on Commission approval of the Buyback Exemption, and reiterate their position that the Commission should not approve such exemption. The JU argue, yet again, that if the Commission desires to provide additional incentives to energy storage resources it should do so through additional NYSERDA programs.

Twelfth, the JU address NY-BEST's comments regarding FERC Open Access Transmission Tariffs (OATT), Con Edison's WDS Tariff, and NY-BEST's support for the Buyback Exemption on the grounds that the Buyback Service charges are often greater than capacity clearing prices, and that Buyback Contract Demand exceedance fees are a barrier to energy storage systems' participation in reserve markets. The JU note that while Con Edison WDS Tariff is the only FERC OATT in effect, they believe that Con Edison's WDS Tariff is an appropriate model for other utilities' future OATTs.

The JU note that they oppose NY-BEST's essential argument that stand-alone energy storage systems should be granted free use of the utility distribution system to participate in wholesale markets. More specifically, the JU note that Buyback Service Contract Demand Charges only apply to the amount of Contract Demand in excess of the Standby Service Contract Demand. The JU further contend that the impacts of high short-duration demands resulting from participation in the reserves market would be lessened due to longer demand measurement intervals used for billing purposes, resulting in smaller demand values.

The JU note that Con Edison Buyback Service customers elect their own level of Buyback Service Contract Demand, and that energy storage customers can manage or avoid Buyback Service Contract Demand exceedance fees through their own bidding behavior in the NYISO markets. The JU argue that any Buyback Service Contract Demand Exceedance Fees imposed on a customer demonstrate the higher level of service required by the customer than what such customer had been paying for. The JU note that the Commission has approved Contract Demand Charges to reflect a customer's maximum potential demand that it might place on the utility's system, that the utility must build infrastructure to meet such maximum demand, and that the Contract Demand exceedance fees are designed to ensure that the customer is paying for its share of the utility's distribution system.

Thirteenth, the JU state that both AEEI and NYECC's comments related to implementing an RDM for Standby Service customers are moot. The JU notes that the Commission has already required that customers voluntarily participating in Standby rates be included in the relevant parent service class RDM as part of the 2019 Standby Rate Order, that some utilities already have an RDM for those customers that are billed under Standby Service on a mandatory basis. The JU states that the only outstanding issue related to the treatment of utility revenues is for existing Standby Service customers which are not covered by an existing RDM at some utilities.

Fourteenth, the JU reply to MI and NYECC's calls to modify the Reliability Credit or otherwise maintain the value of such credit for existing customers. The JU state that the Commission has required that the Reliability Credit be applied to the Contract Demand Charge, and that the stated purpose of the Reliability Credit is to provide a proxy of the grid value of minimizing customer usage of the grid during summer on-peak periods. The JU note that the Commission required that the updated Standby rates include improved price signals to customers including revised Contract Demand Charges, which in some cases will be significantly reduced or eliminated, and more granular Daily As-Used Demand Charges, both of which reflect a better measure of grid value and incentive to operate customer generation in a reliability fashion during on-peak periods than the existing Reliability Credit. The JU argue that these modifications to the underlying Standby rates do not justify maintaining the value of the Reliability Credit for existing customers or modifying the Reliability Credit to be calculated based on Daily As-Used Demand, as recommended by NYECC and MI, respectively, and that the Commission should consider whether a Reliability Credit is still needed at all.

Fifteenth, the JU address MI's comments regarding vintaging existing Standby Service customers into the existing Standby rates. The JU observe that maintaining two sets of Standby rates, one for vintaged existing customers and another for all others, could be complex for utilities to implement and confusing for customers. Beyond implementation issues, the JU note that in the 2019 Standby Rate Order the Commission itself recognized the potential for customers to experience bill impacts related to updated Standby Service rates, and did not make any recommendations or findings to address such impacts through vintaging. The JU further note that following the 2019 Standby Rate Order, the Whitepaper did not recommend any form of vintaging either.

The JU observe that to the extent that the Whitepaper's proposals and the JU's recommendations regarding modifications to such proposal represent an improvement to the current Standby rates, and would result in some customers paying more under such improved rates, then the reason that these customers would pay more is because they have not equitably contributed to their costs for service under the current Standby rate design. The JU further observe that any bill impact analysis represents only a snapshot at a given point in time based on then-present usage of the system, and that customer bill impacts will differ over time based on a variety of factors such as weather, changes in end-use technologies used by customers, economic activity, and operations of customer DER.

Finally, the JU responds to AEEI's assertion that Contract Demand Charges that are set above the levels determined based on cost causation principles will undercut the New York's ability to reach its clean energy goals. The JU point out that the very purpose of this proceeding is to establish an ACOS methodology which produces rates which reflect cost causation. The JU argue that the Commission should maintain its longstanding principle that rate designs should be technology neutral, even if stakeholders are unsatisfied with this proceeding's outcome if it fails to produce rates that provide as strong an economic incentive as they desire for clean energy resources. The JU reiterate, again, that if the Commission believes greater incentives are needed to spur the development of particular technologies, it should provide such incentives through utility or NYSERDA incentive programs.

NECHPI

NECHPI requests that the Commission consider several key points to ensure clarity, transparency, and completeness in each of the utilities' ACOS studies. First, NECHPI states that the distinction between Shared and Local costs must remain as clear as possible. NECHPI notes that it disagrees with Con Edison's approach stated during the Second Technical Conference that an entire network of customers could be considered "a small group of customers." NECHPI states that the Commission should maintain its historical definition of local costs as those tied to a single customer, as maintaining such definition will avoid decreased clarity and reduce utility discretion in applying the Decision Tree Methodology. NECHPI argues that inaccurately assigning Shared costs to the Local cost category will have the effect of removing price signals from the Contract Demand Charge since the actions of a single customer would have little impact on the aggregate demand of multiple customers. Similarly, NECHPI recommends clarifying Question 3, such that the question asks whether costs "would", instead of "could", be stranded in the event of a single customer decreasing its demand.

NECHPI also requests that the Commission modify the process for determining the amount of Contract Demand kilowatts (Contract Demand kW). NECHPI requests that such determination be based on a customer's peak demand on a rolling two-year timeline instead of being assessed based a customer's highest historical demand. NECHPI alleges that there is currently no ready avenue for customers to revise their Contract Demand kW downward, and asserts that its recommended modification would incentivize customers to invest in energy efficiency and distributed generation to permanently decrease their peak load.

NECHPI disagrees with certain utilities' reliance on minimum system methodologies used as part of ECOS studies for purposes of determining the Customer Charge. NECHPI argues that the minimum system methodology has not been specifically approved in New York State, and that use of such method results in costs that would otherwise be considered Shared being collected through the Local-based Contract Demand Charge. NECHPI posits that the minimum system methodology designates some demand-related costs, some of which might otherwise be determined to be Shared costs, as Customer costs. Since current Customer Charges are sometimes set below the level required to fully recover Customer costs through the Customer Charge, and Staff proposed to allocate any remaining Customer costs not recovered through the Customer Charge to the Local cost category, a portion of Shared costs designated as Customer costs could be instead allocated to the Local cost category. Instead, NECHPI argues that all demand-related costs should be allocated through the Decision Tree Methodology, including those costs which would otherwise have been included in the customer charge using the minimum system method.

Finally, NECHPI agrees with certain AEEI's proposals regarding the Decision Tree. Specifically, NECHPI agrees with AEEI's request to add an additional question asking whether an injection of power would potentially decrease costs between Questions 2 and 3 in the Decision Tree. Also, NECHPI agrees with AEEI's request to modify Question 4 to consider whether any form of coincident demand, including network peaks, other non-system-coincident peaks, and system-coincident peaks, would increase costs.

NineDot

In its comments, NineDot makes recommendations related to Staff's proposed Buyback Service Contract Demand Exemption for stand-alone energy storage, expresses support for Staff's proposed Decision Tree methodology and NY-BEST's comments regarding such, and expresses support for MicroGrid Network's request for an exemption to Standby Service Contract Demand Charges for stand-alone energy storage.[105] NineDot states that it strongly supports Staff's recommendation to exempt stand-alone energy storage systems from Buyback Service Contract Demand Charges, but recommends several modifications to such exemption.

[105] NineDot also made various recommendations related to potential future NYSERDA energy storage incentive programs and modifications to the compensation structure for services provided by energy storage under the Value Stack Tariff. Neither of these topics are germane to the Commission decision-making on the Whitepaper, therefore a summary and discussion of such topics is not included herein.

First, NineDot recommends that the Buyback Service Contract Demand Charge exemption should be provided to all stand-alone energy storage projects that qualify by December 31, 2030, and that qualification should be based on either (1) the date that the developer makes a 25 percent deposit toward interconnection costs for a project to the relevant distribution utility, or (2) the date of an executed interconnection agreement if a deposit is not required. NineDot argues that Staff's proposed 2025 in-service date deadline to qualify for the exemption is inconsistent with New York's 2030 energy storage targets, and that a short period of only a few years does not provide sufficient time to design, develop, and deploy energy storage projects prior to Staff's proposed deadline. NineDot further argues that using an in-service date deadline, as proposed by Staff, is inconsistent with other eligibility qualifications under the Value Stack Tariff, all of which have been based on the date the 25 percent interconnection cost deposit.

Second, NineDot recommends that the Buyback Service Contract Demand Charge exemption should last for at least 25 years. NineDot argues that the proposed 20-year duration of the exemption is inconsistent with other terms of the Value Stack Tariff, including NYSERDA's typical timeframe for evaluating the economics of projects participating in the Value Stack Tariff. NineDot posits that energy storage equipment will typically require repowering after 15 years, therefore a 20-year exemption would heavily expose stand-alone energy storage financiers to unknown structural changes in operating costs in the remaining five years, potentially resulting in energy storage equipment being abandoned instead of repowered after 15 years.

NineDot notes that it supports the proposed Decision Tree Methodology, and echoes the comments provided by NY-BEST that additional granularity is required. NineDot states that it reviewed MicroGrid Network's request to exempt stand-alone energy storage from Standby Service Contract Demand Charges, and similarly requests that the Commission adopt such proposal.

NY-BEST

In its reply comments, NY-BEST makes five main arguments. First, NY-BEST recommends that the Commission promote uniformity and simplicity among utility ACOS studies by rejecting the Joint Utilities' proposals which NY-BEST contends will add unnecessary complexity and jeopardize the ability to implement the Decision Tree Methodology statewide. Specifically, NY-BEST states that the Commission should reject the JU's proposal to apply the Decision Tree separately for service classification and voltage level at each utility. NY-BEST argues that applying the Decision Tree separately as recommended by the JU would detract from uniformity of ACOS studies among utilities since each utility has significant differences in terms of customer eligibility, primary voltage criteria, and size thresholds used to define service classifications and voltage levels. NY-BEST points out this applying the Decision Tree in this way would add significant complexity to the ACOS process, resulting in utilities filing dozens of spreadsheets by service classification and voltage instead of a single spreadsheet as contemplated in the ACOS Whitepaper. NY-BEST further argues that allowing the utilities to apply the Decision Tree on a service classification- and voltage-specific level would allow the utilities to answer the same question differently for each service classification even if the voltage level were the same. NY-BEST argues that allowing the Decision Tree to be applied on a service classification- and voltage-specific level provides a greater opportunity for the utilities to interpret the Decision Tree to meet their desired results, that doing so would conflict with the uniformity, simplicity, and transparency objectives of the ACOS Whitepaper, and that this level of complexity further complicates setting rates in a revenue-neutral manner.

Second, NY-BEST recommends that the Commission adopt Staff's proposed CP/NCP ratio for apportioning costs between Shared and Local categories instead of the Joint Utilities' proposed CP/ICMD ratio. NY-BEST cautions that the choice of allocator has significant impacts on the ultimate rate design, especially for residential customers. NY-BEST posits that NCP is the primary cost driver for lower voltage portions of the electric distribution system, that CP is the primary cost driver for higher voltage portions of the system, and therefore reasons that Staff's CP/NCP ratio is reflective of cost causation principles as it reflects the degree to which different customers use infrastructure at different levels of the system. NY-BEST further argues that the Commission should reject the JU's proposed CP/ICMD ratio. NY-BEST contends that use of the ICMD makes the assumption that the entire system is built to handle all customers consuming their maximum demands at the same time with no diversity of load. NY-BEST admits that while infrastructure proximate to the customer must be sized to meet ICMD, the costs considered in the ACOS Methodology, even if considered on a FERC Account basis, are not granular enough to isolate facilities that are specifically installed to meet the maximum demand of any specific customer. Therefore, NY-BEST concludes that the CP/NCP ratio is the correct allocator for apportioning costs between Shared and Local.

NY-BEST also recommends that the Commission reject the JU's fallback allocator: the ratio of Average On-Peak demand to Contract Demand. NY-BEST argues that there is little evidence to support such a ratio on the record, that such ratio has not been used elsewhere, and questions whether each utility's Contract Demand values reflect present grid conditions. NY-BEST also takes issue with the JU's allegation that NY-BEST's initial comments seek merely to reduce the allocation of costs to Local to advance its own interests – NY-BEST notes that the same could be said of the JU advancing its interest in maximizing the revenue obtained through Contract Demand Charges.

Third, NY-BEST requests that the Commission take appropriate steps to ensure that Con Edison, O&R, and Central Hudson (the "downstate utilities") file compliant ACOS studies following its determinations in this Order. NY-BEST requests that the Commission direct each utility to provide the rationale for its answers to the Decision Tree by voltage. NY-BEST argues that this will ensure that the utilities' ACOS results are sufficiently transparent, and note that several of the utilities answers to Decision Tree questions have already proven surprising. NY-BEST requests that the Commission retain the right to require the utilities to revise their compliance ACOS filings following this Order if the utilities file studies which diverge significantly from the Decision Tree Methodology and from other utilities. NY-BEST requests that the Commission require the utilities to apply the long-standing definition of shared and local costs, especially as it pertains to longstanding definition of local costs as those pertaining to infrastructure built to serve a single customer, and that the Commission establish guidance and guardrails to ensure that hypothetical edge cases are not the basis for answers to Decision Tree questions.

NY-BEST requests that the Commission direct the downstate utilities to provide data on a FERC Account basis, and should consider how much accuracy it is willing to sacrifice to allow the downstate utilities to file ACOS results based on functionalized revenue requirements. NY-BEST posits that there is a tradeoff between the granularity of data available and the ability to accurately answer Decision Tree questions, requesting that the Commission provide additional guidance and guardrails for utilities to follow if it allows the downstate utilities to implement the ACOS Methodology on a functionalized revenue requirement basis. Although the downstate utilities have produced ACOS results in this proceeding based on the Decision Tree Methodology, NY-BEST argues that such results do not constitute a demonstration that the results using the functionalized revenue requirement basis would be the same as results on a FERC Account basis, and further argues that the JU cannot make such assertion without performing a side-by-side comparison.

NY-BEST expresses concern regarding utilities' ability to answer Question 6, i.e., to examine whether a Local cost should be recovered from Buyback Service customers, arguing that the functional revenue requirement basis precludes the utility from answering Decision Tree Question 6 with sufficient granularity. NY-BEST posits that while the workpapers filed by Central Hudson, National Grid, NYSEG and RG&E demonstrate sufficient granularity to answer Question 6 for relevant cost categories, Con Edison and O&R's workpapers did not provide sufficient granularity to do so. NY-BEST argues that the Commission should not accept any ACOS study which does not answer Question 6 for the relevant asset types. NY-BEST also expresses concern that the Decision Tree excludes costs allocated to Local from answering Question 6 if such costs are apportioned between Shared and Local categories as a result of answering "yes" to Question 5. NY-BEST recommends that the Commission add Question 6 again subsequent to answering "yes" to

Question 5 to further differentiate the Local costs that are recovered through Standby rates versus Buyback Rates.

Fourth, NY-BEST requests that the Commission recognize the impact of Buyback Contract Demand Charges on energy storage projects participating in the wholesale markets, and reject the JU’s arguments that such charges are an accurate price signal. Contrary to the JU’s position in its initial comments, NY-BEST argues that Buyback Contract Demand Charges are not an appropriate price signal but rather serve solely as a barrier to prevent energy storage systems from exporting more power than they import. NY-BEST contends that the only costs energy storage systems cause via export are identified in interconnection studies and paid for by the interconnection applicant through interconnection charges. NY-BEST posits, instead, that Buyback Service Contract Demand Charges are non-seasonal and non-time differentiated charges applied to exports on the basis of speculative assumptions regarding cost causation which also carry financially devastating penalties for exceeding the specified Buyback Contract Demand limits.

NY-BEST disagrees with the JU’s position that Buyback Service Contract Demand Charges should continue to be imposed for energy storage systems for energy storage systems that are not utility-controlled, and that the Commission should authorize additional NYSERDA funding if it desires to provide incentives to overcome market barriers. NY-BEST notes that third-party owned energy storage resources dispatched by utilities[106] currently pay Buyback Service Contract Demand Charges. NY-BEST further contends that the JU’s comments appear to express a preference for utility control and/or ownership of energy storage assets, which NY-BEST argues is in conflict with efforts

[106] For example, as part of a Non-Wire Alternative project.

to establish a merchant energy storage sector with dual participation in the wholesale and retail markets.

NY-BEST cautions the Commission to be mindful of how Standby and Buyback demand charges affect energy storage systems' ability to participate in the wholesale capacity market. NY-BEST notes that energy storage resources are evaluated against the Cost of New Entry when the NYISO determines whether to apply minimum bid requirements known as Buyer-side Mitigation (BSM). NY-BEST notes that a recent NYISO market monitoring report identified that only three of the thirteen energy storage projects passed BSM tests for the 2019 class year, and that the report identified distribution utility charges as the first reason why such units fail BSM tests. NY-BEST further posits that failing the BSM requires that energy storage resources bid a higher price into the market, and that such mitigation can result in higher prices for consumers, especially in constrained areas where the pricing for a relatively small amount of wholesale resources can have a significant impact on the clearing prices of capacity markets.

Fifth, NY-BEST provides further support for the Buyback Service Contract Demand Charge Exemption, and responds to comments submitted by the JU. NY-BEST argues that the Exemption will provide time for the Commission and stakeholders to determine if the reformed Standby and Buyback rate designs resulting from this proceeding are sufficient to accurate capture the cost causation and benefits from stand-alone energy storage resources, as well as give such resources time to refine their business models to accommodate the new Standby and Buyback Service rates. NY-BEST argues that the JU's prediction on the magnitude of the cost-shift resulting from approval of the Exemption is overly optimistic in terms of the amount of energy storage deployed, and the over-stated valuation of the Exemption based on the Buyback Service Contract Demand Charge currently in place at Con Edison. NY-BEST notes that the JU argue that the impacts of the Exemption to customers will be material and the impacts on the NYISO market from Standby and Buyback charges will be negligible, whereas, according to NY-BEST, the opposites are true. NY-BEST also argues that the JU's citation of the solar market as a cautionary tale for over-incenting energy storage resources is misplaced, as energy storage resources will continue to pay the Standby Service rates developed through this proceeding.

AUGUST 2021 COMMENTS

Joint Utilities' Alternate Allocator Methodology

At the Third Technical Conference, the JU presented their proposal to implement an alternate allocation methodology (AAM) for apportioning costs between the Shared and Local categories (JU AAM Proposal). On July 29, 2021, the JU filed a letter and supporting workpapers more fully describing their AAM Proposal. The JU note that the utilities and other parties have each interpreted the Whitepaper's Decision Tree differently and made various recommendations to modify such methodology. While the JU state that they do not waive their previous positions regarding the Whitepaper, the JU state that the intent of their AAM Proposal is to find attempt to find an approach and analytical method which is acceptable to stakeholders and can be readily and consistently implemented in utility rate proceedings.

The JU state that the AAM Proposal would be implemented within the Decision Tree framework proposed in the Whitepaper, however, under the AAM Proposal Decision Tree questions would only be answered at the customer connection voltage level, with upstream assets considered fully Shared. For each of the costs at the customer connection voltage level, the AAM Proposal would answer Decision Tree Questions 3 through 5 in a predetermined manner, answering "no" to Question 3, "yes" to Question 4, and "yes" to Question 5 such that all asset-based demand-driven costs are apportioned between the Shared and Local categories using an allocation factor. The JU state that the allocator used to apportion costs between Shared and Local would be developed separately for each service class and voltage level. The JU propose to set the Local portion of costs using the ratio of the utility's demand measure used to allocate demand-related costs at the customer connection level from its ECOS study to the ICMD.[107]

As an example, the JU explain that Con Edison uses a blend of NCP and ICMD to allocate demand-related costs for secondary voltage customers and uses NCP to allocate demand related costs for primary voltage customers. Therefore, Con Edison would allocate secondary voltage costs to the Local category based on the ratio of blended NCP and ICMD to ICMD, and would allocate primary voltage costs to the Local category based on the ratio of NCP to ICMD. In their July 29 workpapers, the utilities demonstrate that Con Edison and O&R are the only two utilities which allocate secondary voltage demand-related costs using a blend of NCP and ICMD in their ECOS studies, whereas each of the other utilities ECOS studies allocate demand-related costs using NCP for all voltage levels.

<u>AEEI</u>

AEEI recommends that the Commission reject the JU's AAM proposal as a whole, but consider two portions of the proposal for independent adoption. AEEI states that the overall JU AAM proposal fails to live up to the main goal of this

[107] This differs slightly compared to the Whitepaper's proposed allocation factor, which set the Shared portion of mixed costs based on the CP/NCP ratio.

proceeding to establish a methodology for designing Standby and Buyback Service rates which align as closely as possible with the real impacts of customer usage on system costs. AEEI argues that the JU AAM proposal, requiring that all relevant costs go through a predetermined path of the Decision Tree with no attempt to provide rationale for how such path would better align with actual use of the system, would predetermine the outcome of the ACOS methodology through negotiation in this proceeding resulting in a different form of opaque negotiated rates after three years of effort to move away from such process. AEEI notes that an ACOS methodology that closely reflects the actual use and deployment of assets on the utility system is critical for successful implementation of Standby and Buyback Service rates. AEEI reiterates its position that all costs that could be reduced by an injection of power or a decrease in demand should be categorized as Shared costs, and reiterates the importance of minimizing the amount of Shared costs recovered through Local charges, as inaccurate cost recovery can nullify the financial benefits of demand reductions and injections for customers.

AEEI recommends that the Commission independent consider two elements of the JU AAM proposal. First, AEEI recommends that the Commission approve the JU AAM proposal’s treatment of system costs at higher voltage than the level that a customer class is interconnected to, i.e., that higher voltage-level costs above the level that a customer class is interconnected to be considered fully Shared. AEEI note that treating these higher voltage level costs as fully Shared is reflective of real-world electric grid design. As an example, AEEI note that while a utility may install dedicated primary voltage lines for large primary voltage customers, it is improbable that any substation or primary voltage equipment would be deployed to serve a specific secondary voltage customer, and that if such a scenario were ever to arise, such secondary voltage customer would likely be required to pay excess distribution facilities charges which would not be considered part of base rate cost recovery.

Second, AEEI notes that while the JU's AAM Proposal represents an improvement over previous utility-proposed iterations, the Commission should not sacrifice the Decision Tree. AEEI state that in the JU's March 2021 workpapers, several utilities allocated their entire secondary voltage distribution network costs to the Local category, in spite of the fact that in either a Network or a Radial utility system these secondary facilities would be physically mixed between Shared and Local costs. AEEI posits that while it makes sense that secondary voltage costs would be mixed between Shared and Local, the JU's AAM proposal would answer Decision Tree Questions 3 through 5 in a predetermined manner to result in all secondary system costs being apportioned between Shared and Local using the allocation factor, obviating the Decision Tree by basing the outcome on a predetermined path that requires no decisions at all. AEEI recommends that the ACOS methodology employed be based on sound rationale for answering Decision Tree questions, rather than simply agreeing to specific outcomes in advance for the sake of expedience. AEEI notes that it continues to support the modifications to the Whitepaper's Decision Tree related included in its initial and reply comments.

AEEI notes two issues with JU AAM proposal which it contends are inconsistent with cost causation principles. First, AEEI notes that it explained in its reply comments how allocations of costs between Shared and Local using an allocation factor is only loosely related to the actual makeup of Shared and Local costs on a system, and continues to recommend that in the long term determinations of whether a cost is Shared or Local should be based on careful examination of a sample of distribution infrastructure. AEEI also recognizes, however, that such a study would cause further delays in this proceeding, and that use of an allocator for apportioning mixed costs between Shared and Local is the best practical solution for the near term. AEEI notes that the Whitepaper's ratio of CP/NCP better represents electric system design compared to the JU's preferred allocators based on ICMD, stating that no part of the electric grid is designed to accommodate the maximum, non-coincident historical demands of each individual customer if all such peaks were to occur simultaneously.

Second, AEEI points out that Con Edison seems to have set its Customer Charges shown in its July 29, 2021 workpapers supporting the AAM Proposal to fully recover Customer costs instead of setting such charges at the current levels. AEEI states that this change was not identified in the JU's narrative explaining the AAM proposal, and if the modification was intentional AEEI recommends that the Commission reject this portion of the AAM proposal. AEEI notes that customer charges are typically set through negotiation at a level different than what a utility ECOS study suggests in part because stakeholders often do not agree with the methodologies used to determine customer costs in utility ECOS studies – for example, AEEI and other stakeholders do not agree with Con Edison's minimum system methodology. AEEI argues that this proceeding is not the proper venue for the Commission to fully consider or adopt Con Edison's minimum system methodology, and recommends that the Commission instead adopt the Whitepaper's recommendation to set Standby and Buyback Service Customer Charges at the same level as the Customer Charge of the parent service class. AEEI recommends that the Commission consider investigating the impact of Con Edison's minimum system methodology in ECOS studies more generally outside of this proceeding.

City

The City states that it continues to believe that the allocation factor proposed in the Whitepaper is a reasonable approach for allocating costs between the Shared and Local categories, and recommends that the Commission reject the JU's AAM proposal and other proposed alternate allocation factors. The City asserts that the JU's proposed AAM would forego much of the granular analysis of utility cost causation and categorization included in the Decision Tree Methodology, and in fact would eliminate virtually all nuance in the Decision Tree by answering Questions 3 through 5 the same way for all assets at the relevant connection voltage level. The City contends that the JU have failed to demonstrate why their proposed AAM proposal is consistent with the direction provided by the 2019 Standby Rate Order, or that such proposal would produce Standby and Buyback Service rates that are more reasonable that the Whitepaper's proposed allocation factor. Further, the City notes that although the JU allege that their proposed AAM is intended to be responsive to stakeholder concerns, the use of ICMD within such allocation factor is neither justified nor responsive to stakeholder feedback.

The City notes that the JU have continued to advocate for including ICMD within the allocation factor for apportioning costs between Shared and Local based on the argument that ICMD better reflects diversity within a customer class, but argue that the JU have not offered an explanation or example of what costs ICMD captures that the ratio of CP to NCP allocation factor proposed by the Whitepaper do not. The City asserts that the use of a service class's NCP within the allocator is more intuitive and reasonable since it directly reflects the maximum demand imposed on the grid at any given moment. The City contends that it is unclear that the ICMD is necessary for assessing diversity at the service class level, and therefore that the JU have not adequately demonstrated why the use of ICMD is necessary or preferable.

The City further argues that the JU's recommended allocation factors based on ICMD each result in a considerable shift of costs from the Shared category to the Local category, when compared to using the Whitepaper's proposed factor, yielding results that are a significant departure from the Whitepaper's proposals and the positions raised by other stakeholders. The City reiterates and notes its support for NY-BEST's reply comment positions, noting that the primary impact of using ICMDs is to increase the percentage of costs allocated to the Local category; that, contrary to the JU's claims, ICMDs are actually less capable of capturing the effect of load diversity; and that increased Contract Demand Charges will negatively impact energy storage systems' daily operations and thus jeopardize the State's ability to meet its climate goals.

Multiple Intervenors

In its comments, MI recommends that the Commission reject the JU's AAM Proposal. While MI states that it is generally supportive of the methodology proposed in the Whitepaper, it reiterates and provides further support for its requests in its initial and reply comments that (1) existing customers that would pay higher bills under the redesigned Standby Service rates should be vintaged into the current rate levels with periodic adjustments; and (2) that the Commission should maintain the economic value of the Reliability Credit for customers that use the redesigned Standby Service rates. MI urges that the Commission resolve the remaining Standby Rate issues expediently, since the Commission's overall review of Standby Service rates has been ongoing since 2016 and continued regulatory uncertainty regarding the Standby Service and associated rates impedes, instead of facilitates, customer development of on-site generation.

MI makes three points supporting its recommendation that the Commission reject the JU's AAM Proposal. First, MI asserts that the JU AAM Proposal lacks adequate support. MI argues that the JU's AAM Proposal is complicated and was made very late into an already long-running proceeding, further arguing that stakeholders had little time to examine and react to the JU's AAM Proposal given that such proposal seeks to resolve methodological issues in a very different manner than the proposals included in the Whitepaper, and would result in unacceptable rate impacts on certain existing customers. MI contends that the JU's AAM Proposal provides little to support further process and delays in this proceeding.

Second, MI highlights the differences between the JU's AAM Proposal and the methodology proposed in the Whitepaper, and argues that since the JU's proposal seeks to modify Standby rates in a manner directly contrary to the Whitepaper, the AAM Proposal should be rejected. MI argues that the lower Contract Demand Charges resulting from the Whitepaper methodology are an implicit admission that the current Contract Demand Charges are too high and should be reduced. MI notes that, instead of reducing Contract Demand Charges, the JU AAM Proposal would result in material increases to existing Standby Service customers. MI notes that the JU AAM Proposal results in very different allocations of costs between Shared and Local compared to the Whitepaper, and would move Standby rates in the opposite direction from the Whitepaper's recommendations.

Third, MI argues that the JU AAM Proposal would result in unacceptable high bill impacts for certain existing Standby Service customers. MI notes that the JU AAM Proposal would result in higher bills for 17 of NYSEG's 28 existing Standby Service customers, with 10 of those 17 customers anticipated to pay more than 10 percent more than the existing Standby rates, and eight of those ten with bill impacts approaching or exceeding 40 percent. Similarly, MI notes that 16 of National Grid's 34 existing Standby Service customers would pay higher bills under the JU AMM Proposal, with seven customers of those 16 customers paying more than 10 percent higher bills, and four of those seven paying in experiencing bill impacts in excess of 20 percent. MI notes that while only four of the 21 existing RG&E Standby Service customers would experience bill increases, three of those four customers would experience bill increases exceeding 30 percent. MI argues that bill increases of such magnitude on existing Standby Service customers are unacceptable and contrary to the public interest. MI further notes that, even absent modifications to the Standby Service rates, there are other rate pressures increasing certain customer bills including the impacts of the COVID-19 pandemic, climate and energy policy initiatives, and various then-ongoing rate proceedings.

MI recommends that existing Standby Service customers that would be harmed by the change in methodology for setting such rates should be accorded an option to continue service under the existing rate levels, subject to periodic adjustments for revenue requirement updates. MI asserts that the imposition of material bill impacts on existing Standby Service customers due to a methodological change is problematic, inequitable, and should be addressed in a manner that eliminates, or at least minimizes, such impacts. MI argues that there is little an existing Standby Service customer can do in response to either the Whitepaper or JU’s the proposed changes in methodology. MI notes that certain customers operating small on-site generators which only provide a small portion of such customer’s total demand would experience large increases in Daily As-Used Demand Charge costs under the Whitepaper proposals, while customers with significant Contract Demand amounts would experience large bill increases under the JU proposals.

MI argues that, unlike current full-requirements customers who may contemplate installing on-site generation in full knowledge of the newly-designed Standby rates, existing Standby Service had previously designed their systems and usage patterns around a different longstanding Standby Rate-setting methodology. MI contends that existing customers’ reliance on the then-existing rates and methodology was reasonable at the time, and such decisions cannot be undone now, and further argues that a majority of the existing Standby Service customers’ on-site generation projects would have been developed and operational before receiving any form of notice that the Commission would be revising the then-current methodology.

MI notes that the Commission has previously provided vintaging rate treatment to other DER technologies. MI cites four examples of net energy metering (NEM) eligible technologies being vintaged into various iterations of NEM, and one example of certain DERs being vintaged into a particular valuation for the Value Stack following significant changes to the valuation of certain Value Stack components. MI asserts that it would be highly inequitable to grant some developers and certain customers vintaging options as a means of protecting the value of some DER projects, while refraining to offer similar protections to existing Standby Service customers who would experience material and detrimental impacts due to modifications in the Standby Rate design methodology.

Mechanically, MI points out a recommendation made in NYSEG and RG&E’s Rate Panel testimony during the last NYSEG and RG&E rate proceeding,[108] which MI asserts could be used to implement its recommended vintaging. MI states that under this approach the current rates could be updated for differences in revenue requirement to remain available as an option for existing Standby Service customers, and further clarifies that while this option should be made available to all existing Standby Service customers, those customers who are not detrimentally impacted by the newly-designed rates should not be forced to continue paying the current rates. As an alternative if the Commission determines not to provide vintaging options for existing Standby Service customers, MI recommends that the Commission implement a gradual, extended phase-in of the newly-designed Standby rates, or to allow the affected customer to return to the rates offered in its Otherwise Applicable Service Classification.

MI recommends that the Commission should modify the Reliability Credit to apply against Daily As-Used Demand Charges instead of Contract Demand Charges. MI notes that the rates following the Whitepaper’s proposals result in significant reductions or even effectively the elimination of the Contract Demand Charge rate. MI notes that while significant reductions in the Contract Demand Charge from current levels may be appropriate, the value of the Contract Demand-based Reliability Credit would be similarly decreased, and that reductions in the

[108] This recommendation was made in witness testimony, but was not incorporated into the Joint Proposal filed in that proceeding or considered by the Commission in its determination on the Joint Proposal.

Contract Demand Charge are offset by increases in the Daily As-Used Demand Charge. MI notes that for some high-voltage customers, these modifications will mean that such customers would effectively not pay a Contract Demand Charge, but also that such customer would earn no Reliability Credit regardless of the performance of such customer's on-site generation facilities.

MI recommends that since Standby Service customers would be subject to very expensive Super-Peak Daily As-Used Demand Charges, and the value of the Reliability Credit would be substantially reduced, that the Commission should instead modify the Reliability Credit to be based on limited avoidance of Super-Peak Daily As-Used Demand Charges. MI states that it is flexible as to how the Reliability Credit would be modified, but also offers a potential structure whereby customers meeting pre-determined reliability criteria could be exempted from one day per month of Super-Peak Daily As-Used Demand Charges. MI states that its example structure would preserve the economic value of the existing Reliability Credit, continue to incentivize reliable operation of customers' on-site generation, and spare customers from a modest potion of the greatly increased Daily As-Used Demand Charge.

NECHPI

NECHPI urges the Commission to reject the JU's AAM proposal, and instead uphold the Whitepaper's proposed methodology for determining Shared and Local costs. NECHPI argues that the JU's AAM proposal undermines the Commission's intent of creating a clear and consistent method for determining Shared and Local costs statewide, and would instead result in a continuation of the status quo of cost allocations determined by an opaque rate case negotiation process.

NECHPI expresses concern that the JU's AAM proposal would remove most of the Decision Tree from consideration, and instead assert that certain Decision Tree Questions would be answered the same for all applicable costs, resulting in all such costs being apportioned between Shared and Local based on an allocation factor. NECHPI states that these answers are logically inconsistent, that any decrease in demand would not relieve assets, and that any increase in coincident or non-coincident demands would incur costs. NECHPI also expresses concern that the JU's AAM proposal would entirely remove Question 6 from consideration, precluding the possibility of certain local costs being excluded from Buyback Service Contract Demand Charges.

NECHPI further alleges that the JU's AAM proposal would be unreasonably opaque and inconsistent among utilities. NECHPI points out that while Con Edison proposes to use the ratio of an unspecified blend of ICMD and NCP, divided by ICMD, other utilities do not rely on ICMD and thus would use different allocation factors for the same sets of costs.

<u>NineDot</u>

NineDot expresses its support for the NY-BEST and AEEI's August 2021 comments regarding the JU's AAM proposal. NineDot characterizes the JU's AAM proposal as an unsupported, eleventh-hour attempt to undo the detailed and careful Decision Tree Methodology proposed in the Whitepaper, and requests that the Commission reject the JU's proposal.

<u>NY-BEST</u>

NY-BEST recommends that the Commission reject the JU's AAM Proposal, and provides additional information supporting its positions included in its initial and reply comments. NY-BEST argues that the JU AAM Proposal is not responsive to the Commission's 2019 Standby Rate Order in several regards. First, NY-BEST points out that the 2019 Standby Rate Order requires that utilities must provide supporting information regarding how costs would be allocated between Shared and Local categories. NY-BEST asserts that the JU AAM Proposal does not provide require that the utilities justify the allocation of costs between Shared and Local, but instead lumps all costs together by voltage level and uses unsupported allocation factors to apportion costs between Shared and Local categories. NY-BEST further argues that the JU have not adequately explained how their proposed NCP/ICMD allocator accurately reflects the proportion of shared and local costs required to serve customers. NY-BEST also notes concern regarding Con Edison and O&R's proposed use of the ratio of a blend of NCP and ICMD to ICMD, stating that such a ratio mathematically places a floor on the proportion of costs would be allocated to Local based on the NCP to ICMD blend percentage[109] - NY-BEST argues that this result seems arbitrary and has not been adequately justified.

Second, NY-BEST points out that the 2019 Standby Rate Order clearly intended for there to be the possibility of a difference between Standby and Buyback Contract Demand Charges, however, NY-BEST asserts that the JU's AAM Proposal does not provide any ability to make such distinction since costs would not flow through Decision Tree Question 6. Third, NY-BEST argues that while the JU AAM Proposal would implement a consistent approach across all utilities envisioned by the Commission, it does so at the expense of many of the other features of an ACOS study that the 2019 Standby Rate Order required. NY-BEST also notes that Con Edison and O&R are the

[109] For instance, a 50/50 blend of NCP and ICMD would produce an allocation factor which can be no less than 50 percent Local, whereas a 75/25 blend of NCP and ICMD would produce a floor of 25 percent Local, and a 25/75 blend of NCP and ICMD would produce a floor of 75 percent Local.

only utilities which propose to implement a blended NCP and ICMD allocation factor for some customer classes, reducing consistency among utility approaches. NY-BEST argues that the Whitepaper proposal is responsive to the 2019 Standby Rate Order and will result in rates that will help meet New York's policy objectives, while the JU's AAM Proposal will do neither.

NY-BEST reiterates the positions it supported in its initial and reply comments, and states that nothing convincing in the JU AAM Proposal which would cause it to change its positions. NY-BEST contends that while the JU characterize their proposal as seeking to address the concerns of non-utility stakeholders by providing a reduction in allocation of Local costs from the current levels for many customer classes, the JU's AAM Proposal would, in fact, raise Contract Demand Charges for customers most likely to install larger energy storage systems at Primary voltage levels.

NY-BEST contends that the JU's AAM Proposal, having been submitted three months after the final rounds of comments and five months after the third Technical Conference and proposing such a drastically different proposal to the Whitepaper, conflicts with the Commission's objectives of promoting fair, orderly and efficient proceedings. NY-BEST asserts that the JU's AAM Proposal constitutes a last-ditch effort to offer a stipulated settlement position on the apparent basis of Con Edison's concern that Contract Demand Charges would be set too low for High Tension customers. NY-BEST asserts that if the Commission were to adopt the JU AAM Proposal, future Standby and Buyback rates would be set on the basis of a stipulated settlement just like they were when Standby and Buyback Service rates were first developed in 2003.

NY-BEST provides additional support for its preferred allocation factor, the ratio of CP to NCP, noting that the allocation of costs to the Local category will be self-adjusting as developers construct more energy storage systems. NY-BEST explains that as the amount of energy storage on the electric grid increases the relative amount of NCP will increase compared to the amount of CP, and, therefore, when the allocation factors are re-examined an increasing amount of NCP compared to CP would result in a higher proportion of costs being allocated to Local instead of Shared. NY-BEST provides an example showing current ratios of CP/NCP decreasing from the current mid-to upper-ninety percentiles to as low as the mid-fiftieth percentile. NY-BEST recommends that these allocators be re-examined during utility rate proceedings, or as frequently as annually. NY-BEST contends that, due to the self-adjusting nature of the CP/NCP allocation factor and the small number of customers currently taking Standby Service, using the Whitepaper's CP/NCP allocation factor will not result in significant cost-shifts to customers that do not take Standby Service.

NYECC and MTA

For their comments regarding the JU's AAM proposal, the Metropolitan Transportation Authority (MTA) join NYECC in submitting joint comments. NYECC and MTA note that well-designed cost-based rates can help provide price signals to customers to manage their load profiles to reduce their overall costs, and that all customers would share in that benefit due to a reduced need to continue to build underutilized infrastructure to meet growing peak demands. NYECC and MTA note that there is a "risk versus reward" aspect to offering optional rates to all customers, and urge caution that development of such rates does not intentionally pick winners and losers. NYECC and MTA agree with the Whitepaper's proposal to develop Standby and Buyback Service rates using an ACOS model, with the goal of producing a reasonably consistent approach across utilities, and agree with the general outcome that customers participating in the resulting rates with high on-peak and super-peak demands would likely pay higher bills due to increased Daily As-Used Demand Charges. NYECC and MTA state that the ACOS model and Decision Tree should be periodically reexamined either as part of utility rate proceedings or as frequently as annually.

NYECC and MTA express concern that the JU's AAM proposal significantly deviates from prior Commission guidance and from the Whitepaper's recommendations. NYECC and MTA allege that the JU seem to be overly concerned with the Whitepaper's results which reduces Contract Demand Charges to near zero for high tension customers, since this should not be a concern at all if the proportion of Shared and Local costs are determined objectively and analytically. NYECC and MTA state that the JU's AAM Proposal appears to discriminatory against high tension customers, since the AAM Proposal appears to be solely aimed at altering the Contract Demand Charges which such customers would pay under the Whitepaper recommendations to instead attain a particular predetermined outcome for a particular set of customers.

NYECC and MTA note that the opaque allocation of costs between Shared and Local Charges are the root of customer complaints going back decades, and that the JU's AAM proposal would result in outcomes that are not objectively arrived at but in predetermined compromise positions which would render the Decision Tree useless as an analytical tool. NYECC and MTA observe that such a result would be little different from the status quo, that is, rates determined by agreement as was done in the past and not through an objective analytical approach. NYECC and MTA state that they strongly recommend that the Commission reject the JU's AAM Proposal.

NYECC and MTA also note that the workpapers submitted by Con Edison on July 29, 2021, do not abide by the Commission's directive to maintain the same Customer Charge for Standby rates as the parent service class. NYECC and MTA contend that Con Edison may be attempting to increase its fixed aggregate Customer Charge to compensate for the reduction in Contract Demand Charge revenues. NYECC and MTA recommend that the rules regarding Contract Demand amounts should be simplified, and that the utilities should base Contract Demand amounts on the past one or two years of a customer's peak demand. NYECC and MTA state that this more frequent resetting of Contract Demand amount would encourage customers to minimize their historic peak demands.

Finally, NYECC and MTA reiterate NYECC's position from its initial and reply comments seeking bill impacts related to the Buyback Exemption to help the Commission determine the appropriate duration for such exemption.

UIU

In its comments, UIU reiterates its concerns regarding development of demand-based rates for mass market customers, and also addresses the JU's AAM proposal. First, UIU restates its interest in being presented with a comprehensive bill impact analysis using various scenarios and a sensitivity analysis prior to the Commission's determination on demand-based rates for mass market customers. UIU states that it continues to support its previously-offered comments in this proceeding that: (1) stated its concerns with developing mass market demand-based rates using the ACOS methodology; (2) the stand-alone energy storage Buyback Exemption should be capped; and (3) its concerns regarding the lack of consistency among utility ECOS studies has not been addressed. UIU expresses concern regarding the potential for intra-class subsidies which could drive up rates for customers that do not participate in the optional rate, and expresses further concern that investments needed to comply with the CLCPA will increase costs to customers and that those customers that choose not to participate in the optional demand-based rates will bear an unfair proportion of such burden through an intra-class subsidy.

UIU notes that it has previously requested a comprehensive bill impact analysis related to the proposed ACOS methodologies, and further requests that a comprehensive bill impact analysis comparing mass market demand rates among six different scenarios be presented to stakeholders prior to the Commission's determination in this proceeding. The six scenarios UIU requests are: (1) the current demand rate, if available for each service class; (2) rates developed based on the utilities' September 2019 ACOS filings; (3) rates developed based on ACOS studies using the Whitepaper's allocation factor; (4) rate developed based on ACOS studies using the JU's preferred CP/ICMD allocator; (5) rates developed based on ACOS studies using the JU's alternate ratio of average on-peak Daily As-Used demands to average contract demands; and (6) the JU's AAM proposal. UIU recommends that further analysis and discussion pertaining to development of mass market demand-based rates should take place in the existing VDER Rate Design Working Group using the format provided in workpapers submitted in Case 17-01277 on November 16, 2018. UIU concludes that there is insufficient information presented to date to understand if the proposed JU AAM methodology is just and reasonable to implement statewide for designing mass market demand rates.

Second, UIU argues that the JU's AAM proposal should not be adopted as an appropriate ACOS methodology. UIU states that it is concerned with any approach which relies on ICMD to develop demand rates, including the two previous JU proposed allocation factors and the JU’s AAM proposal. UIU points out that even though the only JU member utility which currently uses ICMD as part of its ECOS study is Con Edison, the JU propose to incorporate an ICMD-based allocation factor at each of the investor-owned utilities. UIU contends that the JU did not provide evidence that the ICMD is an accepted ratemaking tool in other jurisdictions, and failed to either adequately support use of the ICMD for statewide implementation or provide adequately standardized ECOS study procedures.

Joint Utilities

The JU address five points in their August 2021 comments. First, The JU state that they have supported rate structures that accurately reflect the costs of operating the electric distribution system, and that well designed rates would strike a balance between cost-causation, customer orientation, and economic sustainability. The JU argue that cost-based rates benefit customers by encouraging efficient actions, and investments, and use of the electric system to lower long-run costs for all customers. The JU states that the core issue the Commission must consider in this proceeding is whether the rates developed using the Whitepaper recommendations, and stakeholder-recommended modifications thereto, result in just and reasonable rates for all customers, especially in light of the Whitepaper’s likely result of minimal Local cost allocations for some of the utilities’ customer classes. The JU argue that these results are unreasonable because these outcomes shift delivery costs incurred on behalf of certain standby customers to all other customers. The JU state that their AAM Proposal is intended to acknowledge and address stakeholder concerns.

Second, the JU address concerns expressed by stakeholders regarding consistency among utility ACOS results which may produce different cost allocations between customer classes and differ among utilities. The JU argue that both the Commission and the Whitepaper seek consistency in the approach and methodology used for developing the ACOS study, and did not intend to require complete consistency in the results themselves. The JU contend that arguments seeking consistency among the ACOS results of different customer classes and at different utilities ignore the differences in characteristics of each utility's distribution system, and differences in the definition and usage characteristics of the utilities' customer classes. The JU argue that their AAM approach can be readily and consistently implemented in utility rate cases.

Third, the JU address stakeholder concerns regarding transparency of the AAM approach, such as claims that the AAM relies on opaque methods for determining Shared and Local costs. The JU claim that the AAM is a transparent approach to assigning costs that would be applied consistently among all of the utilities, and that although the JU have previously presented their preferred answers to Decision Tree questions, the AAM approach provides an alternative way of responding to those questions in a manner that produces results more in line with many of the stakeholders positions. Since the AAM builds on the cost allocation factors included in utility ECOS studies, and the utilities' ECOS studies are established in utility rate proceedings, the JU conclude that the AAM proposal can be easily and transparently integrated into the Decision Tree framework.

Third, the JU reiterate their opposition to vintaging for existing Standby Service customers that may experience bill impacts. The JU reiterate arguments made in their initial and reply comments that both the Commission's 2019 Standby Rate Order and the Whitepaper anticipated bill impacts to some customers, neither recommended vintaging, and reiterated complexities and potential customer confusion if utilities had to maintain two sets of Standby rates. The JU argue that vintaging would run counter to the Commission's efforts to develop and maintain Standby rates as a theoretically pure cost-reflective rate for accurately matching customer cost causation with the rates they pay.

Finally, the JU reiterate their position on revenue impacts of implementing updated Standby and Buyback rates, i.e., that the only outstanding issue to be decided relates to treatment of revenue differences for existing Standby Service customers at utilities where mandatory Standby Service customers are not included in an RDM. The JU requests that the Commission direct those utilities with Standby Service revenues not covered by RDMs to establish a true-up mechanism so that the impact of updated Standby rates does not produce either a utility revenue windfall or shortfall. The JU further suggest that the treatment of Standby Service revenues could be addressed in each of the utilities' next rate proceedings.

SEPTEMBER 2 AND 20, 2021 COMMENTS

Joint Utilities

In their September 2, 2021 AAM Reply comments, the JU address three topics. First, the JU address stakeholder comments claiming that the record established in this proceeding supports the Decision Tree Methodology proposed in the Whitepaper, while also alleging that the JU did not present sufficient evidence to support their positions. The JU contend that it is the Whitepaper never explained why its proposed allocation factor based on the CP/NCP ratio is reasonable, and that such proposal is itself unsupported. Further, the JU state that many stakeholders support the Whitepaper's proposed allocation factor, but provide no evidence of explaining why this allocation is reasonable. Conversely, the JU assert that the record does support their positions regarding Shard versus

Local cost allocations, based on their presentations at the Second and Third Technical Conferences, workpapers, and reply comments.

Second, the JU address stakeholder comments alleging that the use of allocation factors among utilities is inconsistent since Con Edison's approach differs from other utilities. The JU contend that this argument ignores that each of the JU's allocation factors for apportioning Shared and Local costs are consistent with the Commission-accepted ECOS methodologies filed in each utility's rate proceedings. The JU argue that the AMM Proposal is a methodology that can be applied consistently to utility-specific ECOS studies.

Third, the JU address stakeholder requests that the Commission accept the Whitepaper proposals and reject the JU recommendations due to the substantial record supporting the Whitepaper. The JU urge the Commission to make decisions based on the merits of the arguments contained in the comments, and not based on the headcount of stakeholder positions.

Sur-reply Parties

The Sur-reply Parties note that it is rare for the diverse stakeholders represented to make a joint filing, and state that while they would not typically file sur-reply comments, doing so represents an equal opportunity for the Sur-reply parties to respond to the JU's unsolicited AAM Reply comments. The Sur-reply Parties address each of the JU's three arguments.

First, the Sur-reply Parties address the JU's allegation that the Whitepaper's allocation factor is insufficiently supported and explained. The Sur-reply Parties contend that while the JU have stated that the allocation factor used to apportion mixed Shared and Local costs should reflect the greatest diversity of demand on the system, the JU have not justified their position by explaining how their preferred allocator would result in a cost allocation that better fits the Commission's definition of Shared and Local costs. The Sur-reply Parties note that, contrary to the JU's assertions, stakeholders have provided justification and support for the Whitepaper's proposed allocation factor, and the JU's position that such arguments are not compelling doesn't mean that the arguments aren't present in the record.

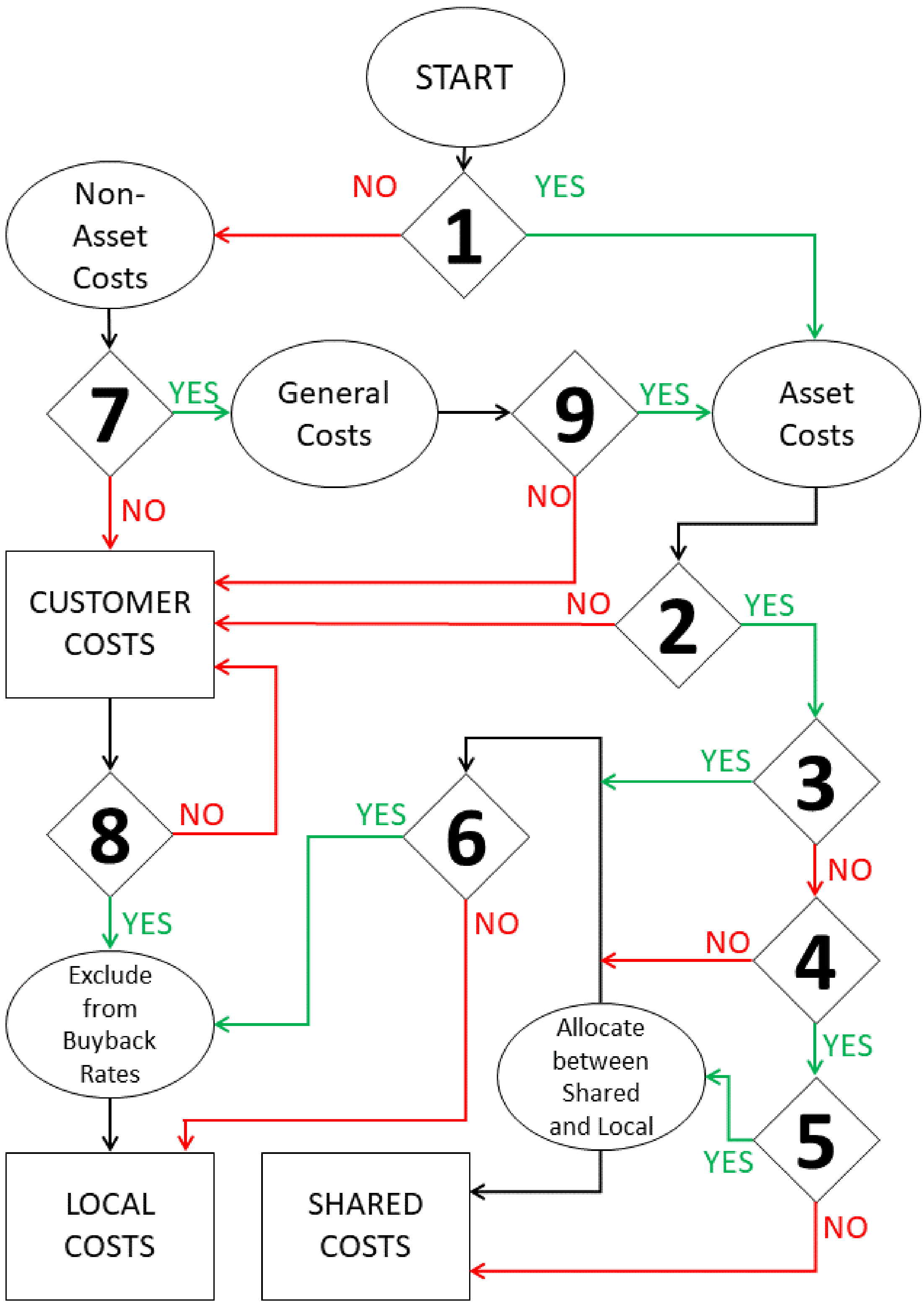
Second, the Sur-reply Parties note that although the JU's preferred allocation factors may be consistent with the ECOS methodologies and studies the utilities file in their rate proceedings, such ECOS methodologies do not achieve the outcomes sought by the Commission in previous Orders or in the development of an ACOS methodology. The Sur-reply Parties note that that the allocators used in utility ECOS studies predate the present proceeding, were not developed for the purpose of and allocating costs between Local and Shared categories, and such ECOS methodologies have only been accepted as inputs to rate proceeding settlements instead of specifically approved on their own merits. The Sure-reply parties conclude, therefore, that the JU's preferred allocators' inclusion in a utility ECOS study does not provide sufficient rationale to adopt such allocators for use in ACOS studies. The Sur-reply Parties contend that the Whitepaper's proposed allocation factor, on the other hand, was developed specifically for the purpose of allocating costs between Shared and Local categories, and better reflects the Commission's definitions of Shared and Local costs uniformly across all utilities.

Third, the Sur-reply Parties address the JU's request that the Commission consider the merits of submitted arguments, not only the number of submissions. The Sur-reply Parties contend that not only were stakeholder comments opposing the JU

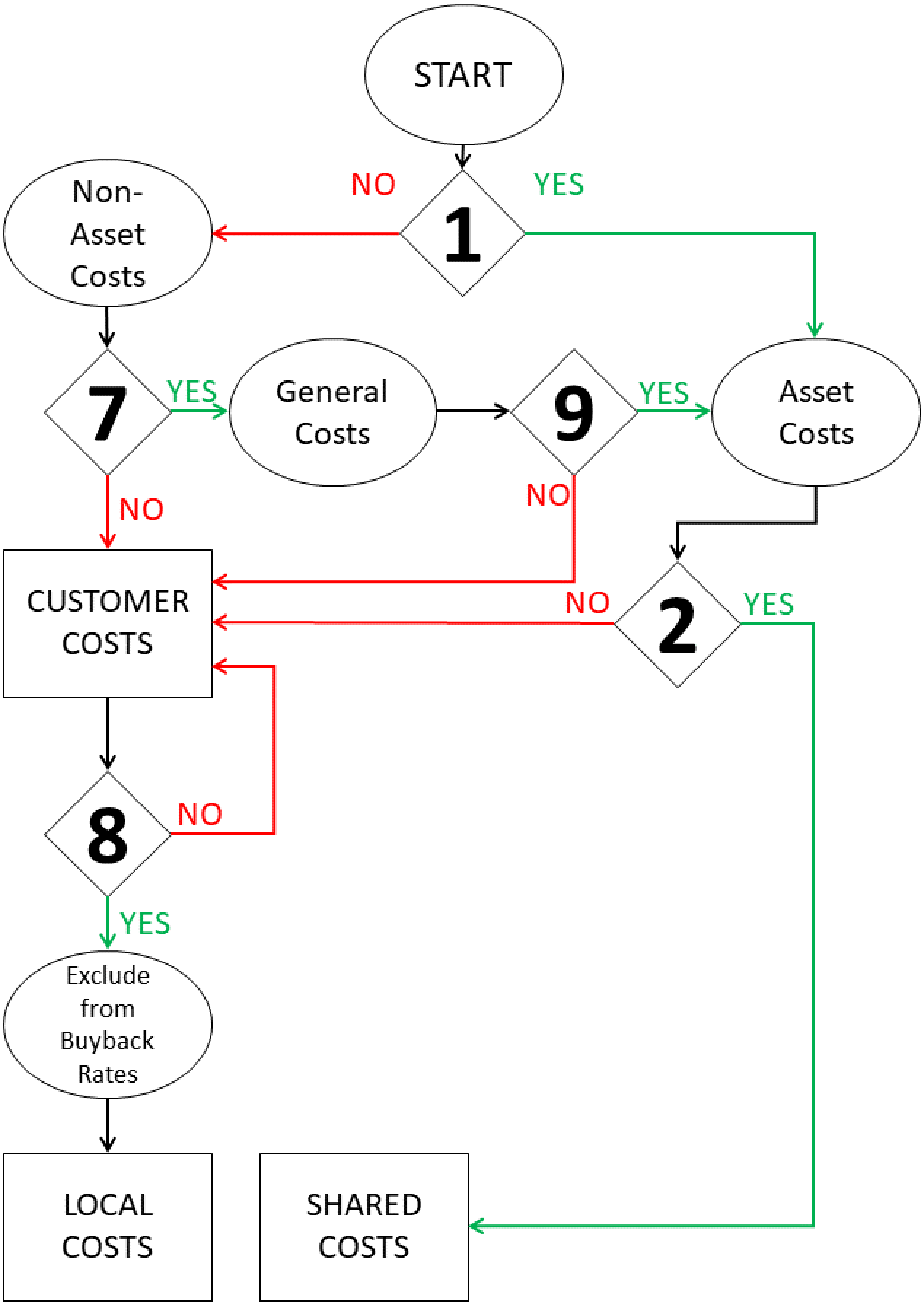
AAM Proposal numerous but also compelling in their merits. The Sur-reply parties point out that while the only the JU support their AAM Proposal, such proposal has garnered both broad and deep opposition from diverse interest groups including municipalities, customer interest groups, and clean energy technology advocates.

APPENDIX B – UPDATED 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 a decrease 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?