STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

WHITEPAPER ON STANDBY AND BUYBACK SERVICE RATE DESIGN AND RESIDENTIAL VOLUNTARY DEMAND RATES

December 12, 2018

I. Introduction and Overview

Through the issuance of the VDER Transition Order in March 2017, the Public Service Commission (Commission) began the transition of compensation for Distributed Energy Resources (DERs) to methodologies that reflect the actual value provided by those resources to the grid and to society and that enable a distributed, transactive, and integrated electric system.[1] The VDER Transition Order also contemplated the development of methodologies to more accurately reflect the costs that DERs impose on the grid. For example, customers with DERs reduce distribution grid usage but continue to rely on the availability of the grid, such that if their bills decrease to reflect their reduced usage but have no element that reflects the continued need for availability, costs caused by those customers would be shifted to other ratepayers. In addition, where excess generation from the DER is sold directly to the utility, that may impose similar grid availability costs. In general, the rates intended to recover appropriate costs for customers in these categories are Standby Service rates and Buyback Service rates. This Whitepaper recommends modifications to the Standby and Buyback Service rates currently in place at New York's investor-owned electric utilities[2] to more accurately reflect costs and benefits and to ensure that those rates are available to all interested ratepayers.

Standby Service generally applies to two types of customers. First, Standby Service applies to customers that normally fully supply their own power through on-site generation but maintain a connection to the electric grid for service during generator failure or maintenance. Second, Standby Service applies to customers that supply part of their own power through on-site generation but frequently supplement it with electricity supplied through the electric grid. In general, customers with on-site generation are required to take Standby Service unless (a) the on-site generation qualifies for technology- and size-based exemptions established in Commission orders[3] or (b) the on-site generation has a capacity of less than 15% of the customer's maximum demand. Similarly, customers with qualifying on-site generation are required to take Buyback Service if their on-site generator will inject electricity into the electric grid[4] and is not eligible for

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1 Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (VDER Transition Order).

2 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 (Niagara Mohawk), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

3 Case 14-E-0488, In the Matter of the Continuation of Standby Rate Exemptions, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015). Exemptions are available for: (a) customers who exclusively use fuel cell, wind, solar thermal, solar photovoltaics, sustainably-managed biomass, tidal, geothermal, and/or methane waste generation resources for on-site generation; (b) customers who use combined heat and power (CHP) generators of 1 MW or less in size meeting certain efficiency standards; and (c) customers who use CHP generators between 1 MW and 15 MW of size meeting certain efficiency standards, where such generators are installed between April 20, 2015 and May 31, 2019.

4 Utilities are required to offer Buyback Service to "Qualifying Facilities" as defined in 18 CFR 292 and to "alternate energy facilities," "co-generation facilities," and "small hydro facilities" under New York State

Net Energy Metering or the Value Stack Tariff.[5] Under Buyback Service, customers are paid by the utility for their net injections of electricity into the grid for energy and capacity, based on wholesale prices for energy and capacity in the New York System Independent Operator (NYISO) market.[6] The proposals in this Whitepaper address both standby and buyback charges.

It should be noted that the Standby Service rate designs discussed herein apply to *delivery* service rates. They do not apply to the *supply* component of a standby customer's requirements. Standby customers may elect to receive energy supply from the utility or purchase it from another entity in the competitive market. Where they elect to receive service from the utility, rates for that supply service are independent from Standby Service rates and based on the applicable tariff provisions regarding supply service to customers with their characteristics.

II. Standby Service Rates

In October 2001, the Commission issued Guidelines for the design of standby service rates.[7] The Guidelines explained that service to customers with on-site generation is sufficiently different, in terms of cost imposed on the utility system as compared to usage characteristics, from service to customers without on-site generation to justify different treatment. However, the Guidelines also recognized that sufficient data did not exist to justify the creation of separate Standby Service rate classifications for these customers. Rather, the Guidelines stated that Standby Service should be provided as an alternative within each otherwise applicable full-requirements class tariff, or Otherwise Applicable Service Classification (OASC). The Guidelines described cost-based rate design principles that should be used for developing this alternative, including general avoidance of recovery based on volume, that is kWh, of energy consumed.

The Guidelines required that costs allocated to each standard service classification serve as the basis for designing revenue-neutral,[8] class-specific Standby Service delivery charges. In other words, the existing allocation of costs to the various service classifications, inclusive of customers in each class with on-site generation, would be retained in the distribution delivery

Public Service Law §§ 2 and 66-c. Utilities are not required to purchase net electricity injections from other sources.

5 While the technologies eligible for net energy metering and the Value Stack Tariff are within the bounds of "alternate energy facilities," "co-generation facilities," and "small hydro facilities" under New York Public Service Law §2, Public Service Law §66-j and the VDER Transition Order further specify the rates which utilities must pay for eligible net electricity injections under the applicable Net Metering and Value Stack Rider.

6 For energy injections under Buyback Service, the utility pays a price based on the NYISO-market Location-Based Marginal Price (LBMP) at the time energy is produced. For capacity injections, the utility pays a price that reflects the cost of capacity, or ICAP, that it avoids having to purchase from the NYISO market during the relevant NYISO peak-coincident hour as a result of the customer-generated capacity.

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

8 The Guidelines defined "revenue neutral" to mean that the full-service class would contribute the same revenues if the full class were priced under either the standard service class rates or the standby rates, based on historic usage patterns of the customers in that class. Case 99-E-1470, *supra*, Opinion No. 01-4, p. 7, n. 6.

service charges. The Guidelines explained that Standby Service rates should be designed to recover those distribution system delivery costs through a combination of class-specific Contract Demand Charges and Daily As-Used Demand Charges. The Contract Demand Charge would be designed to recover the costs of "local" facilities, that is, facilities that are closer to a customer's site and were put in place mostly to serve the individual customer. The Contract Demand Charges are fixed for each customer based on the customer's maximum demand. The Guidelines further stated that delivery system facilities located farther from customer sites should be considered "shared" facilities, the costs of which would be recovered in a manner that recognizes the customers' overall demand coincidence with that of the service classification, through Daily As-Used Demand Charges, calculated based on the customer's actual peak demand during the established system peak period each day.

Consistent with the Guidelines, current Standby Service rates established at each utility have three common elements: a Customer Charge, a Contract Demand Charge, and a Daily As-Used Demand Charge. These charges are designed relatively similarly across utilities on a revenue neutral basis using the existing pool of customers in the service classification that a standby customer would otherwise be eligible for if not for its generating facilities (the customer's OASC). The Customer Charge is generally set based on the customer-related costs identified in the relevant utility's Embedded Cost of Service (ECOS) study for the OASC.[9]

Consistent with the Guidelines, the Contract Demand Charge is designed to recover costs that are considered local to the customer, that is, costs for those facilities that are specifically installed to serve a specific customer, cannot be shared with other customers, and are predominantly designed to serve the individual customer's maximum load, regardless of whether that load is coincident with the system peak. The Daily As-Used Demand Charge is designed to recover costs for shared facilities, the need for which is predominantly based on the coincident demand of many customers.

After determining the Revenue Requirement of the OASC based on the ECOS study and subtracting out revenues collected through the Customer Charge, the remaining Revenue Requirement is collected through a combination of a Contract Demand Charge and Daily As-Used Demand Charge. Each of the utilities has a Contract Demand Charge, per kW of Contract Demand, designed to recover the revenue requirement associated with costs local to individual customers. Generally, each customer's Contract Demand is individually set based on the maximum peak kW of demand the customer can draw from the distribution grid.[10] The design of the Daily As-Used Demand Charge varies somewhat from utility to utility; however, every utility has at least an on-peak component, with customers charged for their maximum demand during the on-peak period each day, and an off-peak period, with no charge applied for demand during

[9] The Customer Charge is set based on the ECOS Study results at all utilities except NYSEG and RG&E. NYSEG and RG&E set the Customer Charge based on the Customer Charge of the OASC, which are slightly different than the monthly charge suggested in those companies' ECOS studies.

[10] Although customers may alternately select their own level of Contract Demand kW, since there are financial ramifications to exceeding a self-selected Contract Demand kW amount, many customers choose to accept the Contract Demand kW determined by their utility.

off-peak hours. While both Con Edison and O&R have a higher Daily As-Used Demand Charge during the summer months, Con Edison is currently the only utility to have a two-component Daily As-Used Demand Charge applicable during the Super-Peak hours of the summer. Table 1, below, shows the different Standby Service Daily As-Used Demand elements in place at each of the utilities.

Table 1: Standby Service Daily As-Used Demand Elements at NYS Utilities

Utility	Service Classification	Daily As-Used Demand			Seasonal Differential
		On-Peak	**Super-Peak**	**Off-peak**	
Central Hudson	SC 14	7 AM - 11 PM, weekdays	N/A	All other hours	No
Con Edison	Specific Rates of SC 5, 8, 9, 12, and 13	8 AM - 10 PM, weekdays, non-holiday	8 AM - 6 PM Weekdays, non-holiday	All other hours	Yes
NYSEG	SC 11	7 AM - 10 PM, weekdays, non-holiday	N/A	All other hours	No
Niagara Mohawk	SC 7	8 AM - 10 PM, weekdays, non-holiday	N/A	All other hours	No
O&R	SC 25	8 AM - 11 PM, weekdays, non-holiday	N/A	All other hours	Yes
RG&E	SC 14	7 AM - 11 PM, weekdays	N/A	All other hours	No

It should be noted that while Standby Service rates traditionally apply primarily to large customers with demand metering, each of the utilities other than Con Edison and O&R has Standby Service rates available for residential and small commercial, or mass market, customers, even though these customers are not billed based on demand. In the case of mass market customers, the utilities still nominally use the rate elements of a Customer Charge, a Contract Demand Charge, and a Daily As-Used Demand Charge in their mass-market Standby Service charges. However, the Contract Demand Charge is instead a flat monthly charge based on the demand of an average member of the OASC and the Daily As-Used Demand Charge is based solely on monthly volumetric electric usage (in kWh) instead of demand, as discussed further below.

The application of the Contract Demand Charge and the allocation of revenues between the Contract Demand Charge and the Daily As-Used Demand Charge have been the subject of substantial debate. In general, that revenue allocation, by service classification, is based on the negotiated outcome of proceedings in 2003, referred to as the Standby Matrices.[11] These Standby Matrices are included in Appendix 1.

[11] These rates were implemented for Con Edison and O&R on July 29, 2003 in Cases 02-E-0780 and 02-E-0781 respectively, for NYSEG on July 30, 2003 in Case 02-E-0779, for Central Hudson on December 4, 2003 in Case 02-E-1108, and for Niagara Mohawk on June 21, 2002. Niagara Mohawk's Standby Matrix was recently modified in Case 17-E-0238, as described in greater detail later in this document. RG&E uses a methodology

A. Standby Service Rates for Mass Market Customers

1. Background

As noted above, while Standby Service rates are traditionally applied primarily to large customers with demand metering, each of the utilities other than Con Edison and O&R has also designed and implemented rates applicable to mass-market customers in residential or small commercial service classifications that are not billed based on demand. The mass-market standby rates are based solely on volumetric electric usage in kWh, instead of on demand in kW. The flat monthly customer charge design is similar between the large customer classes and the mass-market customers. However, the Contract Demand Charge revenue requirement for mass market customers is collected through a flat monthly charge that does not vary between customers based on their maximum potential or actual demand. The Daily As-Used Demand Charge revenue requirement is collected through a monthly volumetric per-kWh charge, instead of being based on the sum of actual daily demands during on-peak periods.

Notwithstanding the theoretical availability of Standby Service rates for mass-market customers, such customers generally do not take service under standby rates due to the lack of an on-site generator, an exemption from Standby Service under net energy metering (NEM), or the availability of a mandatory small-customer exemption through May 31, 2019.[12] Further, small commercial demand-metered customers with a maximum demand of less than 50 kW are offered an exemption from standby rates because most customers of that type currently do not have the necessary interval metering. These small demand-metered customers may nonetheless elect to be billed under Standby Service rates if they pay the applicable meter upgrade and communications fees.

2. Staff Proposal

With interval demand-capable metering becoming much more widely available due to the rollout of Advanced Metering Infrastructure (AMI) throughout New York State,[13] mass-market Standby Service rates no longer need to be limited to billing-determinants-based flat fees and volumetric energy usage over a billing period. Rather, rates for mass market Standby Service can be measured and billed on the basis of demand in the same manner as the Standby Service

based on marginal costs marked up to achieve revenue requirement targets, implemented on July 29, 2003 in Case 02-E-0551.

12 Case 14-E-0488, Standby Rate Exemptions, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015). In general, mass market customers meeting the eligibility criteria for an exemption are not permitted to opt-in to standby service; the one exception to this rule is Niagara Mohawk, which does allow such customers to opt in and does not impose a limit on the number of customers. Central Hudson, NYSEG, and RG&E each exempt up to 100, 250, and 150 non-NEM-eligible customers, respectively, from standby rates. Neither Con Edison nor O&R have implemented mass market standby rates or limits to the number of non-NEM-eligible customers exempt from standby rates.

13 Each of the utilities other than Central Hudson either has a Commission-approved AMI rollout plan, or has proposed such a plan for Commission consideration. While Central Hudson is not planning on rolling out AMI to its entire service territory, AMI meters and access to meter data are available to mass market customers for a fee as part of its Insights+ Demonstration Project.

rates applicable to larger customers. As these meter data become available, mass-market Standby Service rates should incorporate a similar design to the larger-customer Standby Service rates.

Staff recommends that the Commission direct each of the utilities to submit draft tariffs implementing redesigned mass-market Standby Service rates to implement Contract Demand Charges based on individual customers' maximum demand and Daily As-Used Demand Charges based on daily maximum on-peak demands to be offered in those areas where AMI is available. Such rates should be designed on a revenue neutral basis to the OASC using load research data currently available and subject to revenue reconciliation within the Revenue Decoupling Mechanism (RDM) applicable to the OASC. These tariff filings should be made within 120 days of the Commission's order addressing the proposals in this Whitepaper. Staff further recommends that the utilities consider modifications to the electric supply rates applicable to mass-market Standby Service customers taking full utility service as well, to align them with the electric supply rates applicable to large Standby Service customers taking full utility service. This recommendation recognizes that newly available AMI data will allow the utilities to provide each customer with an Installed Capacity (ICAP) tag and therefore to provide supply charges based on actual customer ICAP and hourly energy usage at the NYISO Location-Based Marginal Price (LBMP).

B. Eligibility for Standby Service Rates

1. Background

Standby rates are among the most theoretically pure rate designs available for aligning individual customers' contribution to system costs with the rates such customers pay and thereby sending accurate price signals to those customers. Other rate designs offer less accurate price signals due to recovery of multiple cost categories, with potentially different cost drivers, through a smaller number of charges and based on less applicable metrics. This issue arises particularly in mass market rate structures, as not only are highly time-dependent, demand-related costs recovered through a monthly volumetric energy usage charge, but the energy charge also includes a portion of fixed and customer-related costs. This is the case to the extent that the customer charge is designed to recover revenues that are less than the customer-related costs identified in the ECOS study. It follows, then, that a rate design that provides a better match between cost causation and revenue recoveries than the existing rates should be made available to customers wherever possible.

Any rate change necessarily results in bill impacts to individual customers, however, based on individual customers' billing determinants. This is true even if such rate changes are implemented on a revenue neutral basis. Since only those customers that benefit from a rate option based on their current billing determinants (structural beneficiaries), or those who can change their usage to benefit from the rate option, would likely decide to participate in an opt-in rate, bill impacts to non-participating customers may be pronounced and widespread. If the revenue impact due to the alternative rate option is reconciled to all the customers of the OASC, and customers that opt-in to the alternative rate pay less under that rate than the standard rate for the OASC, then customers paying the standard rate will pay more through the RDM than they otherwise would have if there were no alternative rate option. While it is true that customers paying less for service under a rate that correctly matches revenue recoveries with cost causation would otherwise be overpaying for service under the OASC, it is not reasonable to impose significant bill impacts on non-participating customers outside of a rate proceeding without mitigation. While Staff holds the opinion that all customers should have the option to be served under a rate option that contains the same elements (or rates) as the Standby Service rate, it is only reasonable to offer such options if the bill impacts to non-participating customers remain manageable.

2. Staff Proposal

Staff recommends that the Commission direct utilities to file tariff amendments expanding opt-in eligibility for all customers to select the applicable Standby Service rates in lieu of the customer's existing rate structure.[14] This opt-in to standby rates should be effective a period of not less than one year, to avoid customers switching between standby and standard rates to take advantage of seasonal rate fluctuations. In the case of Con Edison, NYSEG and RG&E, these tariff amendments should be filed as part of each utility's next electric rate proceeding, which will allow bill impacts on non-participating customers to be carefully considered and mitigated. For implementation outside of general rate proceedings – in the case of Central Hudson,[15] Niagara Mohawk[16] and O&R[17] – such tariff filings should be made within 120 days of the Commission's order addressing the proposals in this Whitepaper, with any over- or under-collection of revenues to be reconciled with using the OASC's RDM; provided, however, that opt-in standby rates should be offered only to customers if the bill impacts to non-participating customers fall below a certain percentage threshold. Stakeholders are requested to provide comments proposing a reasonable bill impact threshold.

C. Allocated Embedded Cost of Service Study

[14] These opt-in rates would not be "standby rates" under the traditional definition, since there is no onsite generation. For purposes of this whitepaper, however, Staff will continue to refer to these rates as opt-in standby rates.

[15] In Central Hudson's recently concluded general rate proceeding, Case 17-E-0459, the Joint Proposal approved by the Commission allows for updates that arise out of generic Commission proceedings, including Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources. Joint Proposal at 76-77. The Commission Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, issued June 14, 2018, acknowledges the need for filings to accommodate the future outcomes of REV-based proceedings. Order at 73.

[16] In Niagara Mohawk's recently concluded general rate proceeding, Case 17-E-0238, the Joint Proposal approved by the Commission acknowledges other policy proceedings that may necessitate cost recovery of incremental costs or changes in rate design during the term of the Rate Plan, including Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources. Joint Proposal at 115-116. The Commission Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, issued March 15, 2018, acknowledges the need for filings to accommodate the future outcomes of REV-based proceedings Order at 85.

[17] O&R currently has a general rate case pending before the Commission, Case 18-E-0067, with new rates proposed to become effective in January 2019. Depending upon the timing of the Commission's order in this proceeding addressing the proposals in this Whitepaper, it will likely not be possible to incorporate consideration of this proposed tariff filing in that case. Stakeholders are requested to provide comments regarding a process for implementing the proposed tariff filing in the case of O&R.

1. Background

The Allocated Embedded Cost of Service (ACOS) methodology builds upon the existing ECOS study by allocating all costs either on a local basis or on a shared basis. The ACOS approach was initially proposed by Niagara Mohawk in its October 7, 2016 Standby and Buyback Rates filing[18] and was subsequently implemented as part of its recently approved Rate Plan.[19] The ACOS multi-step process is as follows:

- Costs elements are functionalized to various categories under the ECOS, including transmission demand, primary demand, secondary demand, and customer costs, by Service Classification (SC);
- The ACOS methodology then assigns a percentage of shared versus local to each item in each cost category for each SC, for example, transmission costs are generally 100% shared, secondary costs are split but significantly more local in nature, and customer-related costs are generally 100% local;
- These allocated percentages of shared and local are multiplied by the revenue requirements for each ECOS cost category to determine the shared and local revenue requirements for each ECOS function for each SC;
- The revenue requirement to be collected through the Customer Charge for each SC is equal to that SC's customer-related costs. The revenue requirement to be collected through the Contract Demand Charge for each SC is equal to the sum of each SC's local revenue requirements, excepting those already included in the Customer Charge. The revenue requirement to be collected through the Daily As-Used Demand Charge for each SC is equal to the sum of each SC's shared revenue requirements; and
- The typical process of designing rates continues by dividing the applicable Customer revenue requirement, Shared revenue requirement, and Local revenue requirement by their applicable billing determinants to calculate the Customer Charge rate, Daily As-Used Demand rate, and Contract Demand Charge rate.[20]

An illustrative example of this process is provided in Appendix 2.

2. Staff Proposal

The ACOS methodology provides a pathway for periodic review of the revenue allocation between Contract Demand Charges and As-Used Demand Charges as part of general rate proceedings, rather than relying solely on the 2003 Standby Matrix. Allocating each of the cost elements into Customer, Shared, and Local charges produces a more accurate revenue

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[18] Case 16-M-0430, Rate Design Reform Supporting Reforming the Energy Vision, Filing of Niagara Mohawk Power Corporation d/b/a National Grid Regarding Cost Allocation Methodology for Current Standby Rates and Options for Commission Consideration (filed October 7, 2016).

[19] Case 17-E-0238, 2018 Niagara Mohawk Electric Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018).

[20] An illustrative example of the above can be found in Attachment 5 to Niagara Mohawk's October 7, 2016 Standby and Buyback Rates filing.

allocation and rate design among the Standby Service charges. It should be noted that application of the ACOS methodology resulted in revenue shifts from the Contract Demand Charge to the Daily As-Used Demand Charge in the case of Niagara Mohawk.[21] It may not always be the case, however, that use of the ACOS methodology will result in a reduction to the Contract Demand Charge and an increase in the Daily As-Used Demand charge compared to existing rates. Further, any modifications made to rate designs will likely cause bill impacts to individual customers based on the characteristics of their usage, even if such changes are implemented on a revenue-neutral basis to the service classification. The impacts of these rate design changes will need to be carefully weighed.

Staff recommends that the Commission direct each of Central Hudson, Con Edison, NYSEG, RG&E, and O&R to perform an Allocated Embedded Cost of Service (ACOS) study, in accordance with the methodology set forth above, and include electric standby rates designed based on the results of those studies in its next electric rate case proceeding. The process in the ACOS methodology of assigning percentages of shared versus local to each item in each cost category for each Service Classification will require analysis to determine the appropriate assignment for each category of costs.[22] Stakeholders are requested to comment on the extent of supporting data the utilities should be required to provide to support their assignment of costs between shared and local.

D. Granular As-Used Demand Charges

1. Background

Con Edison's Standby/Buyback Pilot, operated under Rider Q, represents a significant development in providing more granular time- and location-varying price signals to customers. Under the Standby/Buyback Pilot, the summer Super-Peak Daily As-Used Demand charge is reduced from a ten-hour period that applies from 8 AM to 6 PM throughout the service territory to a four-hour period that varies by network based on the hours that the network experiences peak load conditions. The specific four-hour Super-Peak periods are defined as the applicable Commercial System Relief Program (CSRP) peak-shaving demand response program call hours, which vary based on which network or radial load area a customer is interconnected to: 11 AM to 3 PM, 2 PM to 6 PM, 4 PM to 8 PM, or 7 PM to 11 PM.[23] These four-hour Super-Peak Daily As-Used Demand charges are only applicable during the summer months, defined as June through September of each year.

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[21] Appendix 3 compares the results of the ACOS methodology with Niagara Mohawk's Standby Matrix from 2002.

[22] Given its complexity, we are not recommending the marginal-cost-based methodology used by RG&E. However, it may be reasonable to utilize marginal costs to inform the ACOS allocations percentages between shared versus local for the various items in each cost and service classification.

[23] The on-peak Daily As-Used Demand period for customers in the 7 PM to 11 PM CSRP call window is also modified from 6 AM to 10 PM, to 8 AM to 12 AM.

In addition to compressing the Super-Peak period, the Standby/Buyback Pilot includes revenue recovery shifts from the on-peak period to the Super-Peak period, which vary based on whether the individual network is considered a high-value network needing additional load relief to help support local reliability under the Distribution Load Relief Program (DLRP), a local reliability demand response program (DLRP Tier 2 Networks).[24] In DLRP Tier 2 Networks, an additional 35% of revenues is shifted from recovery through the on-peak Daily As-Used Demand Charge into the Super-Peak Daily As-Used Demand Charge. Twenty percent of revenues is shifted from recovery through the on-peak Daily As-Used Demand Charge into the Super-Peak Daily As-Used Demand Charge in all other networks.

While the general format of the Standby/Buyback Pilot rates is a reasonable example that other utilities could follow to design more granular Daily As-Used Demand charges, its exact details may not be applicable to the other New York utilities and therefore additional information and process is necessary to develop such rates that could be adopted by the Commission. For example, Con Edison is unique in New York as the only utility to have both an On-Peak and Super-Peak Daily As-Used Demand charge as well as differing CSRP call windows[25] and one of only two utilities with differing DLRP payment rates based on customer location.[26]

2. Staff Proposal

As a first step toward being able to implement more granular Daily As-Used Demand charges for utilities other than Con Edison, Staff recommends that the Commission direct Central Hudson, Niagara Mohawk, NYSEG, RG&E, and O&R to develop more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components during the summer period for their existing standby rates and submit such rates for Commission review and approval. These tariff filings should be made within 60 days of the Commission's order addressing the proposals in this Whitepaper.

To help frame the Commission guidance to the utilities, stakeholders are requested to provide input on the following questions:

- Does each utility require a Super-Peak charge?
- Should each utility implement Daily As-Used Demand rates which vary by season?
- Should the Super-Peak charge apply during the utility system peak demand period, the peak period of the network or load area in which individual customers are located, or the service classification peak demand period?
- Should the Super-Peak charge rate vary depending upon whether a customer is interconnected to a high-value network or load area?

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24 DLRP Tier 2 Networks are defined as the of the ten lowest reliability networks based on a three-year rolling average of Network Reliability Index rankings.

25 Each of the other utilities calls CSRP events during 2 PM to 6 PM only.

26 O&R also offers tiered DLRP payment rates. Niagara Mohawk, NYSEG, and RG&E only offer the DLRP to customers within certain high-value areas. Central Hudson does not offer a DLRP.

- What value or percentage of revenue should be recovered through the Off-Peak, On-Peak and Super-Peak charge?

E. Applicability of the Reliability Credit

1. Background

The Reliability Credit mechanism, as implemented in the REV Track Two Order,[27] is designed to compensate Standby Service customers for consistently and reliably using DERs and other behind-the-meter load reductions instead of taking service from the grid during summer demand-billed hours. Specifically, the Reliability Credit provides a monetary credit based on the kW difference between a customer's Contract Demand kW and the maximum kW demand the customer places on the grid during the on-peak Daily As-Used Demand hours over a two-summer period, multiplied by the customer's applicable $/kW Contract Demand Charge rate. The Reliability Credit is a somewhat imprecise measure, in that it provides a proxy of grid value based on the local Contract Demand Charge measured during the shared Daily As-Used Demand hours during the summer only.

Beyond requiring that all DER be connected behind the customer's meter, Standby Service includes several DER configuration options, including allowing customers to interconnect DER directly to the grid with provision for station power. An example is a grid-connected battery that takes Standby Service for battery charging and discharges directly to the grid. Such a grid-connected, or standalone, energy storage system could potentially avoid paying for any local distribution facilities if the customer charges only during off-peak hours. Utility Offset Tariffs also allow customers to directly connect DER to the grid and offset separately metered usage, the demand-based analog of remote net energy metering. Under this arrangement, it is possible for customers to offset As-Used Demand charges, avoid paying Contract Demand Charges under the Reliability Credit if their generation capacity is greater than or equal to their maximum usage, and potentially earn Value Stack compensation for net injections.

2. Staff Proposal

The availability of the Reliability Credit must be limited in order to avoid double-paying applicable DERs for the value they provide to the grid – once under the Value Stack through the DRV or LSRV, and again through the Reliability Credit – and to ensure that customers pay a fair share of the costs of local facilities. The Commission has already approved similar exclusions for standalone grid-connected electric energy storage systems from earning the Reliability Credit at Con Edison.[28]

Staff recommends that the Commission direct the utilities to modify their respective Standby Service tariffs to restrict eligibility for the Reliability Credit to exclude customers' grid-connected or "front of the meter" DERs that receive Value Stack compensation for exports to the

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[27] Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016).

[28] Case 17-E-0458, Con Edison Energy Storage Tariff, Order Approving Tariff Changes with Modification (issued February 22, 2018).

system, including customers participating in an Offset Tariff option. These tariff filings should be made within 60 days of the Commission's order addressing the proposals in this Whitepaper.

F. Expansion of the Campus Multi-Party Offset Tariff

1. Background

The Standby Service Offset Tariff allows a customer to interconnect its generating equipment to a utility's primary voltage distribution system and offset the Daily As-Used Demand Charge of its separately metered load connected to the secondary voltage distribution system. In this way, the Offset Tariff allows for remote net demand metering, virtually using the utility's distribution system to deliver power from the generator to the customer's end use instead of customer-owned equipment. Under the Offset Tariff, each account where demand is offset in this manner must take service under Standby Service rates.

The Offset Tariff was first instituted at Con Edison and initially allowed only for generation to offset the Daily As-Used Demand of a single building. In 2011, the Commission called for Con Edison to expand the Offset Tariff to allow for a customer with generation to offset load of multiple buildings (of that same customer) in a campus setting,[29] provided that the generator and buildings were located on a single premise, which was later implemented in the Campus Offset Tariff Order.[30] Among the issues considered in the Campus Offset Tariff Order was whether to allow multiple customers to take offset from a single generator under the Campus Offset Tariff, the level of Contract Demand kW amount to charge each building taking service under the Campus Offset Tariff, and whether to require buildings served under the Campus Offset Tariff to be both located on the same premises and electrically interconnected. The Commission determined that multiple customers would not be allowed to take offset from a single generator, required Contract Demand Charges for each building be based on each building's non-coincident maximum demand, and also determined that all buildings served under the Campus Offset Tariff must be located on the same premises, but did not require such buildings to be electrically interconnected.

Con Edison thereafter convened a collaborative to consider expanding the Offset Tariff to include allowing a single generator to offset the load of multiple customers,[31] ultimately resulting in a Con Edison petition to allow such offset to multiple customers provided that such customers were located in the same building.[32] As part of the REV Track Two Order, the Commission required each of the utilities to institute Con Edison's then-current Offset Tariff provisions,

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[29] Case 11-E-0299, Con Edison Offset Tariff, Order Approving Tariff Amendments with Modifications (issued November 17, 2011).

[30] Case 11-E-0299, supra, Order Approving Tariff Amendments with Modifications and Granting Petition for Rehearing (issued October 18, 2012).

[31] Case 13-E-0030, 2013 Con Edison Electric Rates, Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (issued February 21, 2014).

[32] Case 16-E-0196, Con Edison Multi-Party Offset, 13-E-0030 Standby Service Multi-Party Offset (filed April 4, 2016) (Multi-Party Offset Petition).

including single-building and Campus configurations, and required that each of the utilities allow for offset to multiple customers provided that such customers are within the same building, similar to Con Edison's Multi-Party Offset Petition.[33] At this time, all of the utilities have complied by instituting both the single-customer, single-building Offset Tariff; the multi-customer, single-building Multi-Party Offset Tariff; and the single-customer, multi-building Campus Offset Tariff.

Further modifications to the Offset Tariff at Con Edison were implemented subsequent to the REV Track Two Order as part of that company's latest electric rate proceeding.[34] The 2016 Con Edison Rate Order builds upon the Multi-Party Offset Tariff and allows the load of multiple customers in multiple buildings to be offset by a common generator (Multi-Party Campus Offset Tariff), provided that such customers are located on the same premises and are connected to the generating facility via a thermal loop[35] to ensure that such customers are proximate to the generating facility. The Multi-Party Campus Offset Tariff allows for a number of configurations that the current Multi-Party Offset tariff does not (for example, a college campus with a cafeteria separately metered and operated by a third party).

2. Staff Proposal

Staff recommends that the Commission direct Central Hudson, Niagara Mohawk, NYSEG, RG&E, and O&R to develop and file a Multi-Party Campus Offset Tariff similar to that currently in place at Con Edison. Stakeholders are requested to provide comments regarding whether the eligibility requirements for the Con Edison tariff – including the requirement of a thermal loop to establish proximity to the generating facility – are appropriate for statewide implementation, or to suggest alternate requirements. These tariff filings should be made within 60 days of the Commission's order addressing the proposals in this Whitepaper.

III. Buyback Service Rates

Buyback Service was initially implemented in New York in response to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). At the time PURPA came into effect, New York State utilities were vertically integrated, with individual utilities responsible for owning and maintaining power generation, transmission, and distribution systems. PURPA allows eligible generators not owned by the utilities (non-utility generators) to export power onto the utilities' transmission and distribution systems and required the utilities to purchase such power. Buyback Service tariffs were developed to fulfill the utilities' new obligation to purchase power from non-utility generators. The Commission subsequently restructured the generation and bulk transmission businesses, required utilities to sell existing generation stations, and

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[33] Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016).

[34] Case 16-E-0060, Con Edison Electric Rates, Order Approving Electric and Gas Rate Plans, (issued January 25, 2017) (2016 Con Edison Rate Order)

[35] In this context a thermal loop refers to customer usage of generator waste heat through steam, hot water, or chilled water equipment.

shaped the development of the energy and capacity markets operated by the New York Independent System Operator (NYISO). Therefore, many non-utility generators now sell power through the NYISO wholesale markets. However, Buyback Service remains as an option for eligible customer-owned generators that wish to export electricity to the utility distribution system, do not qualify for Net Energy Metering under New York's Public Service Law §§ 66-j or 66-l or other DER compensation options such as the Value Stack tariffs established in Case 15-E-0751, and do not wish to participate directly in the NYISO wholesale market.

Similar to Standby Service, Buyback Service is designed to ensure that customer-owned generators connected to utilities' distribution systems pay their fair share of fixed system costs and costs related directly to serving individual customers. Buyback Service rate design includes the same concepts of a Customer Charge and a Contract Demand Charge employed under Standby Service; in fact, in many cases the same Customer Charge and Contract Demand Charge developed for Standby Service are applied to Buyback Service customers inasmuch as the same types of distribution system infrastructure is required to deliver electricity used or produced by customers. As with Standby Service, the Buyback Service Customer Charge is designed to recover fixed system costs, while the Contract Demand Charge is designed to recover the costs of local facilities specifically installed to meet individual customer needs. Unlike Standby Service, however, Buyback Service does not have a Daily As-Used Demand component. Instead utilities pay Buyback Service customers for net energy and capacity injections. For net energy injections under Buyback Service, the utility pays a price based on the NYISO-market Location-Based Marginal Price (LBMP) at the time energy is produced. For capacity injections, the utility pays a price that reflects the cost of capacity, or ICAP, that it avoids having to purchase from the NYISO market during the relevant NYISO peak-coincident hour as a result of the customer-generated capacity.[36]

A. Grid Access Contract Demand Charges

1. Background

Most utilities charge Buyback Service customers a monthly Customer Charge and a Contract Demand Charge. Similar to Standby Service equivalents, these charges are designed to recover the customer-related costs and local facilities costs associated with customer export of power to the utility grid. They can be considered grid access charges, to the extent that customers interconnected to the grid must pay these charges regardless of whether or not the service is actually used. While the terms of Buyback Service are similar among utilities, there is some variation in whether utilities impose these grid access charges and how such charges are designed.

In the case of buyback-only customers, who do not take service under another service classification, most of the utilities impose a Customer Charge and a Contract Demand Charge

36 Con Edison, Central Hudson, and O&R each purchase ICAP coincident with the specific peak in the NYISO's Zone G-J, which spans from the mid-Hudson Valley into New York City. The Long Island Power Authority purchases ICAP coincident with the NYISO's Long Island zone peak hour. Niagara Mohawk, NYSEG, and RG&E purchase ICAP based on the coincident peak hour of applicable to the rest of New York State. While these three peak hours are often similar, they can occur on different hours and different days of a given year.

based on the standby rate applicable to the customer's OASC; only Niagara Mohawk does not have a Customer Charge or a Contract Demand Charge for buyback-only customers.

There are wider differences among utility practices with respect to charges applicable to dual-service customers, who take service under both buyback and another service classification. For these customers, Con Edison waives the Customer Charge and a Contract Demand Charge is assessed only on generator capacity greater than the customer's maximum demand. Similar to Con Edison, both Central Hudson and O&R charge an incremental Contract Demand Charge for any generator kW served under Buyback Service greater than the maximum annual usage demand served under the other service classification. However, both utilities also impose an incremental monthly Customer Charge or Metering Charge to dual-service customers. NYSEG, RG&E, and Niagara Mohawk do not impose either an incremental Customer Charge or an incremental Contract Demand Charge under Buyback Service to dual-service customers.

2. Staff Proposal

To the extent that a buyback-only customer does not pay a Customer Charge or Contract Demand Charge based on its usage of the grid or, likewise, that a dual-service customer does not pay for additional Contract Demand based on the local facilities that are built to serve its generation over and above those which are already included in the cost recovery of its other service classification, other customers pay for the customer-related or local facilities costs not recovered from the customer that imposes them. To eliminate this cost shift and ensure that all customers pay for their fair share of the costs they impose, Niagara Mohawk, NYSEG, and RG&E should update their Buyback Service rates.

Staff recommends that the Commission direct Niagara Mohawk to design and implement Buyback Service rates for buyback-only customers to include a Customer Charge and a Contract Demand Charge. In addition, Staff recommends that Niagara Mohawk, NYSEG and RG&E be directed to design and implement rates for dual-service customers to include an incremental Contract Demand Charge for generator kW greater than the customer's maximum annual usage demand. These tariff filings should be made within 120 days of the Commission's order addressing the proposals in this Whitepaper.

B. Purchase of Installed Capacity from Buyback Service Customers

1. Background

Each utility's tariff allows eligible customers to sell energy and capacity directly into the NYISO's markets or to the utility through Buyback Service. Even though the utilities' Buyback Service tariffs require that customers meet the same operating requirements imposed by the NYISO to sell energy and capacity to the utility, allowing customers to either sell the NYISO or directly to the utility represents an important option for customers; the interconnection requirements and associated costs, as well as the rates paid by customers, can be different for a

DER selling into the NYISO market versus directly to the utility.[37] While each utilities' tariffs contains language allowing for the purchase of Unforced Capacity (UCAP) from eligible customers through their respective buyback service tariffs,[38] the specific language governing the purchase of UCAP differs slightly among utilities. The tariffs of Central Hudson, Niagara Mohawk, NYSEG, and RG&E each specify that customers with over 100 kW of generation capacity may negotiate a contract with the utility for sale of capacity through the Buyback Service, which in effect means that those utilities are obligated to enter into negotiations with customers to contract for such capacity. While Con Edison's and O&R's tariffs specify that purchases of UCAP through the Buyback Service is permissible, there is no specific tariff language granting customers the right to negotiate with the utilities for such contracts, thereby leaving it to the discretion of Con Edison and O&R as to whether to purchase UCAP through buyback service. DER developers routinely complain that Con Edison is not willing to purchase such capacity through its Buyback Service. This represents a potential barrier to DER adoption.

Also inconsistent among the utilities' Buyback Service tariffs is the amount of UCAP that each utility may purchase from customers. Both Con Edison and O&R's tariffs only allow the purchase of up to 2 megawatts (MWs) of UCAP per customer, whereas Niagara Mohawk's tariff states that the company will purchase up to 80 MWs of UCAP per customer. Central Hudson, NYSEG, and RG&E do not have specified maximum capacity purchase limits in their respective tariffs.[39]

Finally, the NYISO sets UCAP prices based on seasonal and monthly capacity strip auctions, competitive auction processes designed to procure the forecast UCAP needs at an efficient price. While capacity resources participating directly in the NYISO capacity markets must compete in these auctions to determine the price they will be paid for their capacity, UCAP purchased through utility buyback tariffs simply take the market UCAP price without being part of the competitive price-setting process. If a significant portion of New York's UCAP is purchased by utilities from parties not participating in the competitive market, there may be distortionary effects on the market itself.

2. Staff Proposal

Staff recommends that the Commission direct Con Edison and O&R to modify their respective Buyback Service tariffs to require those companies to purchase UCAP from eligible

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37 Customers directly participating in the NYISO markets are charged under the Open Access Transmission Tariff regulated by the Federal Energy Regulatory Commission.

38 UCAP is related to the more commonly-discussed Installed Capacity (ICAP). UCAP accounts for historic availability of capacity suppliers to ensure that the minimum amount of ICAP is obtained. Generally, the amount of ICAP kW provided by a generator is less than its UCAP kW, given that generators are not 100% reliable at all times. To satisfy the NYISO's ICAP requirements, Load Serving Entities, such as utilities, are assigned a UCAP amount requirement and must purchase UCAP either directly from generators or through the NYISO market.

39 While Central Hudson, NYSEG, and RG&E do not specify a maximum capacity limit, PURPA only applies to Qualifying Facilities of 80 MW capacity or less.

customers at the prevailing NYISO strip capacity market price. In addition, Staff recommends that the Commission direct each of the other utilities to file tariff amendments clarifying the utility's obligation to purchase UCAP from customers. These tariff filings should be made within 60 days of the Commission's order addressing the proposals in this Whitepaper.

Staff recommends that the Commission set a maximum project-level UCAP limit of 5 MW for purchases of capacity from technologies not eligible for the Value Stack through Buyback Service.[40] This 5 MW project-level UCAP limit is consistent with the maximum amount of UCAP payments provided through the Value Stack compensation mechanism recently approved by the Commission in its Value Stack Expansion Order,[41] and would be applied uniformly across the state. Upon issuance of a Commission order adopting a UCAP MW limit, Staff recommends that the Commission direct each of the utilities to file tariff amendments as necessary to implement this limit within 60 days of such order.

Stakeholders are requested to provide comment as to whether each utility should set a maximum cumulative UCAP purchase threshold to avoid utility UCAP purchases through Buyback Service distorting the NYISO's UCAP strip auction price-setting process. If so, Stakeholders are requested to provide further comment regarding how such a threshold should be determined.

C. Modification of Con Edison Buyback Contract Demand Charge

1. Background

In the October 2016 Con Edison and O&R Standby/Buyback Rates Report,[42] Con Edison proposed to modify the Contract Demand Charge under its Buyback Service for customers taking service at the primary voltage level. Con Edison explained that currently Contract Demand Charges applicable to Buyback Service customers are set equal to the Contract Demand Charge under the otherwise applicable Standby Service rate and further explained that a portion of substation costs are allocated to and collected through the Contract Demand Charge for standby customers taking service at the primary voltage level.[43] Con Edison noted that it is unlikely for a customer's export to place additional demand on substation facilities. It therefore proposed to eliminate the portion of substation costs included in the Contract Demand Charge for Buyback Service customers taking service at the primary voltage level.

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[40] Niagara Mohawk has advised Staff that it is currently purchasing more than 5 MW of capacity under its buyback tariff from one customer in its service territory That customer should be grandfathered such that Niagara Mohawk continues to purchase its capacity without regard to the new 5 MW limitation.

[41] Case 15-E-0570, supra, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018) (Value Stack Expansion Order).

[42] Case 16-M-0430, Rate Design Reforms Supporting Reforming the Energy Vision, Standby Rate Matrix Study and Recommendations of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (filed October 7, 2016) (Con Edison and O&R Standby/Buyback Rate Report).

[43] This issue is unique to Primary Service customers, as the substation costs are allocated entirely to the Daily As-Used Demand Charge instead of the Contract Demand Charge for customers taking service at the secondary voltage level.

2. Staff Proposal

Staff recommends that the Commission direct Con Edison to modify its Buyback Service Contract Demand Charge to remove the portion of primary voltage substation costs from the applicable Contract Demand Charge, consistent with Con Edison's proposal. This tariff filing should be made within 60 days of the Commission's order addressing the proposals in this Whitepaper. The other utilities should be directed to examine the calculation of their Buyback Service Contract Demand Charge for standby customers taking service at the primary voltage level to determine whether similar modifications are necessary and, if so, the applicable utilities should be directed to file the necessary tariff revisions within 60 days of the Commission's order.

IV. Grid Access Demand Charges for Energy Storage Systems

1. Background

On May 22, 2018, Staff issued the Value Stack Expansion Whitepaper,[44] which proposed, among other things, that the standby and buyback service provisions that would otherwise apply to technologies that are eligible for Value Stack compensation but not eligible for Net Energy Metering would continue to apply, particularly Contract Demand charges to recover local system costs, with the exception that compensation for hourly net injections would be made based on the Value Stack methodology instead of the existing buyback service compensation. Among the technologies which would be newly-eligible for Value Stack compensation were energy storage technologies, including stand-alone systems, energy storage systems paired with consumption load, and regenerative braking systems. While many respondents to the Value Stack Expansion Whitepaper supported the Staff proposal, several commenters expressed concerns. Among the concerns raised by stakeholders were that applying standby and buyback charges to newly-eligible Value Stack technologies could create a barrier to these technologies' adoption by disadvantaging these technologies as compared to already eligible technologies and that the application of standby and buyback service Contract Demand charges to these technologies should be studied further. Commenters suggested that newly-eligible Value Stack technologies be allowed to select either standby service or standard service and that current technology-based exemptions to the standby service be extended to include these technologies.

While the Commission was still considering the Value Stack Expansion Whitepaper, Staff and the New York State Energy Research and Development Authority (NYSERDA) jointly issued the Storage Roadmap.[45] The Storage Roadmap recommended that the Commission implement Staff's recommendations in the Value Stack Expansion Whitepaper with regard to the application of standby and buyback service Contract Demand rates to energy storage projects. However, it also noted that the impacts and outcomes of this approach should be examined in the context of various energy storage use cases, and requested stakeholder feedback to help develop

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[44] Case 15-E-0751, Value of Distributed Energy Resources, Staff Proposal on Value Stack Eligibility Expansion (filed May 22, 2018) (Value Stack Expansion Whitepaper).

[45] Case 18-E-0130, Energy Storage Roadmap, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations (filed June 21, 2018) (Storage Roadmap).

the record for Commission decision in this regard. In particular, Staff and NYSERDA note the that the Federal Energy Regulatory Committee (FERC) Order 841 allows energy storage systems connected to the utility distribution system to charge at the wholesale energy market price when providing wholesale services, whereas charging for distribution services would vary depending upon the applicable distribution rates. Responding to the Storage Roadmap recommendations, commenters suggested that more evaluation is necessary. In particular, commenters expressed concern that application of standby and buyback service Contract Demand charges may reduce economic benefits of operating energy storage systems and that application of distribution-level Contract Demand charges may create a cost and pricing disparity between energy storage systems participating in the wholesale market only and those participating in distribution-level markets. Commenters suggest that charging rates and discharging compensation be provided with specific daily, monthly, and seasonally-granular rates or, in the alternative, that energy storage providers participating in distribution-level markets only be charged the applicable wholesale energy cost plus an adder to recover fixed system costs from such customers.

Subsequent to both the Value Stack Expansion Whitepaper and the Storage Roadmap, the Commission issued its Value Stack Expansion Order. In the Value Stack Expansion Order, the Commission adopted Staff's proposal to apply all provisions of existing standby and buyback service to newly Value Stack-eligible technologies with the exception that net hourly injections from these technologies would be compensated using the Value Stack methodology instead of the applicable buyback service compensation. The Commission notes that "standby service seeks to ensure that customers who generate on-site . . . are charged an appropriate level to support to [sic] the existence and maintenance of the electrical grid," and that "buyback [service] rates similarly ensure that customers who inject energy into the grid provide appropriate contributions to the maintenance of the grid." Responding to stakeholders' requests that newly Value Stack-eligible technologies be offered exemptions from standby and buyback service rates, the Commission states that "exempting customers from [standby and buyback service] rates, and allowing them to instead remain on standard rates not designed with prosumers in mind, carries the potential of allowing those customers to contribute less than the costs they cause and thereby shift costs onto other customers."

2. Staff Proposal

Staff recommends that the Commission continue requiring energy storage systems connected to utility distribution systems to pay the applicable delivery service rates, and, in particular, the applicable standby and buyback service Contract Demand charges. As recognized by the Commission in the Value Stack Expansion Order, both standby and buyback service rates are designed to ensure that the customers making use of electrical grid, both for charging and discharging purposes, pay their fair share for the costs they impose by maintaining and using a connection to the distribution system. In this regard, Staff asserts that the standby and buyback service rates have been established in a just and reasonable manner, and that allowing customers with energy storage systems to avoid such charges would unreasonably shift the cost of such customers' local facilities to other customers.

While Staff recommends the continued application of standby and buyback service charges to energy storage customers, there may be instances where such charges do indeed create uneconomic conditions for energy storage systems in a way that would be unreasonably or inconsistent with the State's policy goals. Stakeholders are requested to describe, in their comments, use cases or instances where application of standby and buyback service charges create an unreasonable barrier to adoption of energy storage systems. The comments should also recommend reasonable alternatives to the existing standby and buyback service charges until such time as energy storage systems under such use cases become economic.

V. Conclusion

The modifications to Standby and Buyback Service rates recommended in this Whitepaper will result in rates that more accurately reflect the impacts that customers impose on the utility system, including costs and benefits. Customers currently served under those rates will have an increased ability to manage their bills and those bills will more accurately reflect the effects of those customers' usage. The recommendations in this Whitepaper will also broaden the availability of those rates, allowing all customers to take advantage of the more precise price signals they provide. Customers interested in managing their load to take advantage of these rates will be able to lower their own bills by reducing the costs they impose on the utility system, avoiding unfair cost shifts.

List of Appendices (Filed as Separate PDFs)

Appendix 1: 2003 Standby Matrices

Appendix 2: Illustrative example of Allocated Embedded Cost of Service (ACOS) methodology

Appendix 3: Comparison of results under ACOS methodology with Niagara Mohawk's Standby Matrix from 2003