ATTACHMENT G

NYPSC STANDBY RATES ORDER

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

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

ORDER DIRECTING STANDBY AND BUYBACK SERVICE TARIFF FILINGS

(Issued and Effective March 16, 2022)

BY THE COMMISSION:

INTRODUCTION

On May 16, 2019, the Public Service Commission (Commission) issued its 2019 Standby Rate Order, which directed modifications to electric utility Standby Service and Buyback Service rates designed to "more accurately align individual customers' contribution to system costs with the rates such customers pay, thereby sending improved price signals to those customers."[1] The Commission expected that these modifications would allow customers interested in managing their load to be better able to "lower their own bills by reducing the costs they

[1] Case 15-E-0751, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-based Rates (issued May 16, 2019), p. 64 (2019 Standby Rate Order).

impose on the utility system" and thereby avoiding unfair cost shifts."[2]

Between September 23, 2019, and September 24, 2019, 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), Rochester Gas & Electric Corporation (RG&E), and Orange and Rockland Utilities, Inc. (O&R) (collectively, the Joint Utilities) made several filings in compliance with the 2019 Standby Rate Order (the September 2019 Tariff Filings). The September 2019 Tariff Filings included: 1) proposed Allocated Cost of Service (ACOS) studies, 2) draft tariff revisions for Standby Service applicable to residential and small non-demand billed commercial (mass market) customers, and 3) Buyback Service rate provisions.

The 2019 Standby Rate Order also directed each utility, as necessary, to file tariff revisions to implement a 5 megawatt (MW) project level Unforced Capacity (UCAP) compensation limit.[3] These revisions went into effect on July 1, 2019.

By this Order, the Commission directs the Joint Utilities to file further revisions to the draft Standby Service tariffs, as well as the draft tariff revisions to current Buyback Service tariff provisions. These revisions, which are described in detail below, are to include rates that are designed using the ACOS methodology adopted by the Commission in the companion order being issued contemporaneously in this proceeding, as well as updated inputs (e.g., revenue

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[2] Id.

[3] 2019 Standby Rate Order, p. 54.

requirements, billing determinants, and Embedded Cost of Service studies), as appropriate.

Additionally, this Order requires Central Hudson to file a revision to its Buyback Service provisions to reinstate tariff provisions that were inadvertently deleted. The provisions are to specify that the maximum Unforced Capacity purchased under Buyback Service will be 5 MW, and that facilities with contracts established prior to July 1, 2019, are exempt from the 5 MW purchase limit.

BACKGROUND

The 2019 Standby Rate Order required the Joint Utilities to file draft tariff revisions to: 1) implement mass market Standby Service rates, based on each utility's proposed ACOS studies, that include Contract Demand charges based on maximum demands, and Daily On-Peak and Super-Peaks As-Used Demand charges, based on daily maximum demands during on-peak hours; 2) revise existing Standby Service and Buyback Service rates to reflect the results of the ACOS studies; and, 3) establish Buyback Contract Demand charges that eliminate the portion of substation costs included in the Contract Demand charge for customers taking service at the primary voltage level. Additionally, Central Hudson, National Grid, NYSEG, RG&E, and O&R were required to develop more granular Daily As-Used Demand Charges. Central Hudson, National Grid, NYSEG, RG&E, and O&R were required to implement Multi-Party Campus Offset tariffs, similar to those implemented by Con Edison.[4] National Grid, NYSEG, and RG&E were required to standardize

[4] Offset tariffs allow for remote net demand metering by virtual use of the utility's distribution system to deliver power from the generator to the customer's end use location instead of using customer-owned behind-the-meter equipment.

applicability of the Buyback Service Customer Charges and Contract Demand Charges. Finally, for Buyback Service customers, National Grid, NYSEG, and RG&E were required to include an incremental Contract Demand Charge for customers that are served under both Buyback Service and an additional service class.[5] The 2019 Standby Rate Order specified the incremental Contract Demand charge would be applied to the customer's generation capacity that is in excess of the customer's maximum annual billed demand under the other service classification.

As articulated in the 2019 Standby Rate Order, the Commission found it reasonable to set a consistent 5 MW project level UCAP compensation limit.[6] Therefore, the Commission directed each utility, as necessary, to file tariff revisions to "implement a 5 MW project level UCAP compensation limit."[7] Further, the 2019 Standby Rate Order adopted the Joint Utilities' recommendation that the 5 MW limit does not apply to non-Value Stack eligible generators with a capacity greater than 5 MW that have existing UCAP purchase contracts prior to the effective date of the revised tariffs. The Commission directed that tariff provisions regarding the purchase of UCAP from Buyback Service customers become effective on July 1, 2019.

On February 27, 2020, the Secretary to the Commission (Secretary) issued a Notice Scheduling Reply Comment Period and Soliciting Additional Input, which requested that each of the Joint Utilities file descriptions of the procedures and requirements which Buyback Service customers must follow to sell capacity services to the utility. On March 16, 2020, the Joint

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[5] These customers are referred to as dual service customers.

[6] UCAP is the generator's installed capacity (ICAP) value reduced by its recent actual forced outage rate.

[7] 2019 Standby Rate Order, p. 53.

Utilities filed the requested information detailing their respective Buyback Service Tariffs and UCAP purchase procedures.

SUMMARY OF SEPTEMBER 2019 TARIFF FILLINGS

Standby rates are generally comprised of three rate elements:

(1) A fixed monthly Customer Charge, designed to recover customer related costs;

(2) A Contract Demand Charge designed to recover costs associated with "Local" facilities. Contract Demand is generally fixed at the highest level of demand experienced by the Standby customer; and,

(3) Daily As-Used Demand Charges designed to recover costs associated with "Shared" facilities. Daily As-Used Demand Charges are applied to billed demand experienced during specified on-peak hours.

Each of the Joint Utilities proposed mass market Standby rates that include Contract Demand Charges based on individual customers' maximum demands and Daily As-Used Demand Charges based on daily maximum on-peak demands. The Joint Utilities developed revenue neutral Standby rates such that the revenues produced for the Standby rates applicable to each service classification would equal the revenues produced by standard rates (referred to as the parent service classification) if all customers in the standard service classification were to take Standby Service. NYSEG, RG&E, and National Grid proposed Standby rate Customer Charges that are equal to those of the parent service classification, whereas Central Hudson, Con Edison, and O&R proposed Standby rate

Customer Charges that were equal to the customer costs that resulted from their respective ACOS studies.[8]

In compliance with the 2019 Standby Rate Order, the Commission required Central Hudson, National Grid, NYSEG, and RG&E to implement multiparty offset provisions like those of Con Edison. Central Hudson, National Grid, NYSEG, and RG&E did so by expanding eligibility of multi-party offset service to multiple buildings connected to the generating facility by a private thermal loop that delivers steam, hot water, or chilled water.[9]

Central Hudson Mass Market Standby Rates

Central Hudson developed its proposed Contract Demand rates by dividing the Contract Demand revenue requirements by the applicable billing determinants. For mass market customer classes, rates were designed based on the load research data corresponding to the Embedded Cost of Service study underlying the Central Hudson ACOS study. Central Hudson proposes that mass market customers' Contract Demand initially be set at the maximum metered demand over the previous twelve months. For customers without twelve months of metered demand history, Central Hudson proposes to initially set the Contract Demand at the maximum metered demand over their entire billing history. The Contract Demand for these customers would be adjusted upward

[8] Determinations on Standby rate intra-class rate design principles for the establishment of Customer Charges, Contract Demand Charges, and Daily As-Used Demand Charges are generally addressed in a companion order addressing utility allocated cost of service study methodologies and subsequent allocation of costs and revenue requirement to the component charges. The updated draft tariff filings required by this Order shall reflect the directives of that order as well, which is being issued contemporaneously in this proceeding.

[9] These provisions are appropriate as proposed and need not be modified in the updated draft tariff filings directed by this Order.

each month until a maximum over the previous twelve months is established.

Central Hudson developed its proposed Daily As-Used Demand rates by dividing the Daily As-Used Demand revenue requirements by the applicable billing determinants. Central Hudson's proposed Super Peak rate was developed by dividing 15 percent of the Daily As-Used Demand revenue requirement by the billing determinants for the Super Peak period. Central Hudson based its 15 percent allocation on its system peak (summer) divided by the average of its summer and winter peaks. Central Hudson's proposed Daily As-Used Demand rates produce seasonal revenues that are generally proportional to Central Hudson's seasonal system demands. Central Hudson currently assesses Daily As-Used Demand Charges for the on-peak hours of 7:00 a.m. to 11:00 p.m. of every weekday. In its draft tariffs, Central Hudson proposes that Daily As-Used Demand Charges be assessed for the on-peak hours of 7:00 a.m. to 11:00 p.m. of every weekday (Peak period) and to implement a Super-Peak period for the hours of 2:00 p.m. to 7:00 p.m. of every weekday during the months of June through September for all customer types except for residential customers. The Super-Peak period aligns with Central Hudson's Commercial System Relief Program (CSRP) capability period and aligns with the hours Central Hudson is likely to experience its system peak. Central Hudson's Super-Peak rates are additive to the Peak rates, meaning that the rate assessed for billed demand in the Super-Peak period is equal to the sum of the Peak period rate and the Super-Peak period rate.

For residential customers, consisting of Service Classification (SC) No. 1 – Residential Service and SC6 – Residential Time-of-Use (TOU) Service, Central Hudson proposes that demand be billed using 60-minute integrated kilowatt

demand, as compared to 15-minute integrated kilowatt demand used for non-residential customers.

Additionally, Central Hudson proposes that customers that opt into Standby Service be allowed to discontinue Standby Service at any time, but not be allowed to opt back into Standby Service for a minimum of one year. Finally, Central Hudson would require all Standby customers, including those electing to opt into Standby rates, to have interval metering and remote meter reading capability. Customers would be responsible for all meter and installation costs and all costs associated with providing telecommunications to the interval meter in order to enable remote meter reading capability.

Central Hudson Buyback Rates

Central Hudson proposes to charge Buyback Contract Demand rates that are equal to the Standby Service Contract Demand rates for all service classes other than the primary voltage level service classes. In accordance with the 2019 Standby Rate Order, Central Hudson proposes to calculate the Buyback Contract Demand rates for customers selling energy to it at the primary voltage level by subtracting the portion of substation costs allocated to contract demand (in the ACOS study) from the total costs allocated to contract demand and dividing by the appropriate billing determinants.

For customers also receiving service under a separate service classification, Central Hudson's currently approved Buyback Service tariff (SC10) reflects the applicability of an incremental demand charge for any generator demand in excess of the maximum annual demand, served through the same meter, billed under the customer's other service classification. Metering and minimum charges under Central Hudson's current Buyback Service tariff provide for recovery of incremental metering costs, and

the utility therefore did not propose modifications to such charges.

Con Edison Mass Market Standby Rates

Con Edison developed its proposed Contract Demand rates by dividing the Contract Demand revenue requirements by the applicable estimated Standby Contract Demand billing determinants. Con Edison estimated the Standby Contract Demand billing determinants by using load research data (for non-demand billed service classifications) or billing data (for demand billed service classifications). The sum of the maximum billing demands (which is reflective of the Contract Demands of the service class) was multiplied by 12 and divided by the sum of the twelve monthly billing demands for customers in the respective class. Con Edison proposes that the Contract Demand for customers without generation facilities that opt into the Standby rate, or "Rate Choice Customers," be initially set equal to the customer's monthly maximum demand up to the most recent 24 months.[10] For any other Rate Choice customer without a generating facility, the initial Contract Demand would be set at the monthly maximum demand of the first monthly bill issued under Standby Service rates. The Contract Demand would automatically increase whenever the demand in a billing period exceeds the Contract Demand.

[10] Con Edison defines a "Rate Choice Customer" as a metered service customer who elects to be billed under Standby Service rates and either: (1) does not have on-site generating equipment; (2) has on-site generating equipment and receives service under SC1 - Residential and Religious Service, SC2 - General Small Service, or the energy-only rate of SC12 - Multiple Dwelling - Space Heating under P.S.C No. 10 - Electricity tariff; or (3) has on-site generating equipment that has a total nameplate rating less than or equal to 15 percent of the maximum potential demand served from all sources.

To develop Daily As-Used rates Con Edison divided the Daily As-Used Demand Charge revenue requirements by the applicable estimated Daily As-Used Demand billing determinants. Con Edison estimated Daily As-Used Demands using load research data on the relationship between non-coincident peak demand and average daily demand for each class. For SC1 and SC2, Con Edison developed Daily As-Used Demand rates for the summer and non-summer months based on the existing summer/non-summer revenue relationship. For all other classes, Con Edison developed the summer and non-summer rates based on the current summer/non-summer rate relationship of the respective classes.

Con Edson currently assesses Daily As-Used Demand Charges: (1) in the winter from 8:00 a.m. through 10:00 p.m., Monday through Friday; and (2) in two time periods in the summer from 8:00 a.m. through 6:00 p.m. and from 8:00 a.m. through 10:00 p.m., Monday through Friday. Con Edison's Super-Peak rates are additive to its on-peak rates. Con Edison proposes that SC1 and SC2 customers who take Standby Service be assessed Daily As-Used Demand Charges between 8:00 a.m. through 10:00 p.m., Monday through Friday. To provide simpler rates, Con Edison did not propose a Super-Peak period for SC1 customers. For SC2, Con Edison allocated transmission costs to: (1) the Winter Daily As-Used Demand Charge, as well as (2) the Summer Super Peak Daily As-Used Demand Charge. The only costs recovered in Summer Super Peak Daily As-Used Demand Charges are transmission costs.

For customers who would otherwise receive service under SC1 demand rates, Con Edison proposes to measure demand as a 60-minute integrated demand. For all other customers, Con Edison proposes to measure demand as a 30-minute integrated demand. Finally, Con Edison proposes that a Rate Choice

Customer be allowed to change its billing rate to or from Standby Service rates no more than once every 12 months.

National Grid Mass Market Standby Rates

National Grid developed its proposed Contract Demand rates by dividing the Contract Demand revenue requirements by the applicable estimated standby Contract Demand billing determinants. National Grid estimated the billing determinants for mass market classes by summing the interval data from its individual load research sample meters and grossed-up those values using appropriate weightings. For demand billed service classes, National Grid used the same billing determinants as it did to design Standby rates in the then-current rate plan. National Grid proposes to set the initial Contract Demand for customers that opt into Standby rates as the maximum demand experienced during the first bill under Standby rates. The Contract Demand would automatically increase whenever the actual demand in a billing period exceeds the existing Contract Demand.

National Grid designed Daily As-Used Demand rates such that 60 percent of Daily As-Used Demand Charge revenues would be recovered though Daily As-Used On-Peak Demand charges and 40 percent would be recovered in Daily As-Used Super-Peak Demand Charges. National Grid proposes that the Peak period for the months of October through May consist of the hours between 8:00 a.m. and 10:00 p.m., Mondays through Fridays (excluding specified weekday holidays). During the months of June through September, National Grid propose two Peak periods: (1) the hours between 8:00 a.m. to 1:00 p.m. and, (2) 6:00 p.m. through 10:00 p.m., Mondays through Fridays, excluding holidays. National Grid proposes a Super-Peak period during the months of June through September between 1:00 p.m. to 6:00 p.m., which is based on a study of the company's system load over the 10-year period

of 2008 through 2017. National Grid proposes distinct (i.e., not additive) Daily As-Used Super-Peak demand rates.

National Grid proposes all Standby customers be billed based on the highest 15-minute integrated kilowatt demand within the applicable billing hours. National Grid proposes that customers opting into Standby Service must remain on the rate for a minimum of one year.

Finally, National Grid proposes that customers opting into Standby Service be required to install an interval meter if they do not already have one installed. Such customers would be subject to an incremental customer charge of $43.46 per month, which is inclusive of the cost of required telecommunications for the meter.

National Grid Buyback Rates

National Grid included an incremental Contract Demand Charge for dual service customers that would be applied to the customer's generation capacity that is in excess to the customer's Standby Contract Demand, as required by the 2019 Standby Rate Order. Additionally, the 2019 Standby Rate Order required National Grid to include a Customer Charge and a Contract Demand Charge for buyback-only customers. National Grid proposes to set the required Customer and Contract Demand rates in the Buyback tariff equal to those of the applicable Standby Service rates.

In compliance with the 2019 Standby Rate Order's requirement that the Joint Utilities establish Buyback Contract Demand Charges that eliminate the portion of substation costs included in the Contract Demand Charge for customers taking service at the primary voltage level, National Grid evaluated the SC7 Buyback Contract Demand rate at the primary voltage delivery level and determined that all substation costs at the Primary Demand level in National Grid's ACOS study are allocated

to the Daily As-Used Demand Charges and not to the Contract Demand Charges in SC7. Therefore, National Grid did not propose to revise the Buyback Contract Demand rate for primary voltage level customers.

NYSEG and RG&E Mass Market Standby Rates

NYSEG and RG&E developed proposed Contract Demand rates by dividing the Contract Demand revenue requirements by the applicable estimated standby Contract Demand billing determinants. NYSEG and RG&E estimated the billing determinants for mass market classes based on a service class load profile. The service class peak demand was multiplied by 12 to calculate the billing determinants. For demand billed service classes, NYSEG and RG&E calculated the billing determinant by summing each customer's annual peak demand in the service classification and multiplying by 12. For Standby Customers without on-site generation, NYSEG and RG&E propose to use the metered demand for the billing month of the first bill to establish a customer's Contract Demand and that a customer's Contract Demand increase if the customer's metered demand increases.

NYSEG and RG&E designed Daily As-Used Demand rates such that the ratio of Daily As-Used Demand Super-Peak rates to Daily As-Used Demand On-Peak rates is two to one. For NYSEG, approximately 50 percent of the revenues are allocated to Daily As-Used Demand Super-Peak Charges and 50 percent of the revenues are allocated to Daily As-Used Demand On-Peak Charges. For RG&E, approximately 40 percent of the revenues are allocated to Daily As-Used Demand Super-Peak Charges and 60 percent of the revenues are allocated to Daily As-Used Demand On-Peak Charges. For non-demand billed service classes, NYSEG and RG&E calculated daily on-peak and super-peak demands based on the service class load profiles. For demand billed service classes, daily on-peak and super-peak demands were calculated by applying ratios

calculated from available hourly metered customer load profiles to the total billed monthly demand for each service class.

NYSEG and RG&E propose to align the Peak and Super-Peak periods with those already established for all other Standby rate customers. For NYSEG, the Peak period for the months of October through November and March through May consists of the hours between 7:00 a.m. through 1:59 p.m. and 6:00 p.m. through 10:59 p.m., Monday through Friday (excluding specified weekday holidays). NYSEG proposes two Super-Peak periods, including: 1) during the summer months of June through September, the period of 2:00 p.m. through 5:59 p.m., and 2) during the winter months of December through February, the period of 5:00 p.m. through 8:59 p.m.

During the months of June through September, RG&E has two Peak periods, including: (1) the hours between 7:00 a.m. to 1:59 p.m. and (2) 6:00 p.m. through 10:59 p.m., Monday through Friday, excluding holidays. For RG&E, the Peak period for the months of October through May consists of the hours between 7:00 a.m. and 10:59 p.m., Monday through Friday (excluding specified weekday holidays). RG&E has a Super-Peak period during the months of June through September that is between 2:00 p.m. to 5:59 p.m.

NYSEG and RG&E propose that all Standby customers without on-site generation be billed using 30-minute integrated demand. NYSEG and RG&E propose that all optional demand billed customers without on-site generation be required to have interval metering and remote meter reading capability. Until advanced metering infrastructure is in place, customers would be responsible for: 1) the incremental costs of interval metering equipment and its installation; 2) the cost of providing remote meter reading capability through an installed method of communication that would allow NYSEG or RG&E to interact with

its meter; and 3) the cost of resolving any communication problems, including any incurred expenses such as obtaining manual meter downloads. NYSEG and RG&E propose that if a customer is unable to restore a non-working method of communication within 60 days, the customer may be returned to its otherwise applicable service class until the method of communication is functioning appropriately. Finally, NYSEG and RG&E propose that customers opting into demand billed service must remain on the rate for a minimum of one year.

NYSEG and RG&E Buyback Rates

For all service classes, other than the primary voltage level service classes, NYSEG and RG&E propose to charge Buyback Contract Demand rates that are equal to the Standby Service Contract Demand rates. In accordance with the 2019 Standby Rate Order, NYSEG and RG&E propose to calculate the Buyback Contract Demand rates for primary voltage level service classes by subtracting the portion of substation costs allocated to contract demand (in the ACOS study) from the total costs allocated to Contract Demand for the respective service class, and then dividing by the appropriate billing determinants. NYSEG and RG&E also included an incremental Contract Demand Charge for dual service customers that would be applied to the customer's generation capacity that is in excess of the customer's maximum annual demand billed under the non-buyback class, as required by the 2019 Standby Rate Order.

O&R Mass Market Standby Rates

O&R developed its proposed Contract Demand rates by dividing the Contract Demand revenue requirements by the applicable estimated standby Contract Demand billing determinants. Like Con Edison, O&R estimated the standby Contract Demand billing determinants by using load research data (for non-demand billed service classifications) or billing data

(for demand billed service classifications). The sum of the maximum billing demands, which is reflective of the Contract Demands of the service class, was multiplied by 12 and divided by the sum of the twelve monthly billing demands for customers in the respective class. O&R's provisions for establishing Contract Demand are similar to those of Con Edison. For a Rate Choice customer, Contract Demand would initially be the customer's monthly maximum demand, up to the most recent 24 months.[11] The Contract Demand would automatically increase whenever the demand in a billing period exceeds the Contract Demand.

O&R currently assesses Daily As-Used Demand Charges from 8:00 a.m. through 11:00 p.m., Monday through Friday (excluding specified holidays). For non-residential customers, O&R charges Daily As-Used Demand rates with the same On-Peak rate for winter and summer, and Super Peak rates that are applied only during the summer months. For customers who would otherwise take service under SC1 or SC19, O&R proposes As-Used Demand Charges with a differential seasonal On-Peak rates, i.e., different On-Peak rates for winter and summer. O&R did not include a Super-Peak period for SC1 or SC19 to provide simpler rates that are more likely to encourage participation while still reflecting its cost of service. For all other customers, O&R proposes a Super-Peak period over the summer months of June

[11] O&R defines a "Rate Choice" customer as a metered service customer who elects to be billed under Standby Service rates and: (1) does not have an on-site generating equipment; (2) has on-site generating equipment and would otherwise receive service under SC1 – Residential Service, SC2 – General Secondary Service– Non-Demand Billed (Metered), or SC19 - Residential Optional Time-of-Use Service; or (3) has on-site generating equipment that has a total nameplate rating less than or equal to 15 percent of the maximum potential demand served from all sources.

through September. Specifically, O&R proposes a summer On-Peak period from 6:00 p.m. through 11:00 p.m. and a Super-Peak period from 8:00 a.m. through 6:00 p.m., Monday through Friday (excluding specified holidays). During the non-summer months, O&R proposes an On-Peak period from 8:00 a.m. through 11:00 p.m. O&R proposes distinct Daily As-Used Super-Peak Demand rates. All other times are considered off-peak.

For the residential classes, O&R used the current relationship of summer and non-summer revenues of the combined SC1 and SC19 classes to develop the revenues allocated to summer and non-summer As-Used Demand Charges. For all other Standby Service customers, O&R developed its Super-Peak Daily As-Used Demand rates to recover a certain percentage of the transmission revenue requirements for the applicable service class. For secondary classes, 50 percent of transmission revenue requirement was allocated to the summer Super-Peak rate. For primary classes, 25 percent of the transmission revenue requirement was allocated to the summer Super-Peak rate. The summer On-Peak rate was set equal to the winter On-Peak rate. O&R estimated daily demands using relationships between non-coincident peak demands and average daily demands developed from load research data for the applicable class.

O&R proposes that demand shall be measured as a 60-minute integrated demand for standby customers who would otherwise receive service under SC1 or SC19. For all other Standby Service customers taking service, demand would be measured as a 15-minute integrated demand, as is currently done for O&R's demand-billed standby customers.

O&R proposes that no incremental metering charges be assessed on residential customers. However, such charges would be applicable to customers in other classes including mass market customers that would otherwise be served under SC2 -

General Secondary Service– Non-Demand Billed (Metered) rates. Finally, O&R proposes that a Rate Choice customer be allowed to change its billing rate to, or from, Standby Service rates no more than once every 12 months.

O&R Buyback Rates

For all service classes, other than the primary voltage level service classes, O&R sets its proposed Buyback Contract Demand rates equal to the Standby Service Contract Demand rates. For primary voltage level service classes, O&R proposes to calculate the Buyback Contract Demand rates by subtracting the portion of substation costs allocated to Contract Demand (in the ACOS study) from the total costs allocated to Contract Demand for the respective service class, and then dividing by the appropriate billing determinants.

SUMMARY OF UNFORCED CAPACITY TARIFFS AND PROCEDURES

As requested in the February 27, 2020, Notice Scheduling Reply Comment Period and Soliciting Additional Input, each of the Joint Utilities filed descriptions of the procedures and requirements which Buyback Service customers must follow to sell capacity to the utility. Central Hudson, Con Edison, NYSEG, RG&E, and O&R (together referred to as the Aligned Utilities), explained that the tariff provisions allowed Buyback Service customers to sell capacity to either the New York Independent System Operator, Inc. (NYISO) or to the utility, and required that such sales meet the same operating requirements imposed by the NYISO to sell energy and capacity. The Aligned Utilities required Buyback Service customers to become a Market Participant (MP) with the NYISO and comply with the applicable NYISO tariff provisions. The Aligned Utilities support this requirement by explaining that since UCAP is a defined and tradable product in the NYISO market, any customer-owned

generator that wishes to sell UCAP to the utility must meet the NYISO requirements. On the other hand, National Grid explains that it treats Buyback Service purchases as load modifiers that reduce the amount of energy and capacity that the utility needs to procure from the NYISO. National Grid explains that because of this treatment Buyback Service customers are not required to register with the NYISO. The utility-specific Buyback Service tariff provisions and procedures are described below.

Central Hudson

In its letter describing Buyback Service procedures, Central Hudson explains that it is not currently purchasing any capacity under the provisions of SC10 Buyback Service. Central Hudson explains that, prior to July 1, 2019, the amount of capacity purchased from a customer was limited only by the definition of a qualifying on-site facility. Effective July 1, 2019, the maximum project-level UCAP for purchase of capacity from technologies not eligible for the Value Stack was set at 5 MW, except for existing contracts established prior to July 1, 2019, which were exempt from the 5 MW UCAP purchase limit. This provision was erroneously deleted from Central Hudson's tariff, effective December 1, 2020.[12]

Con Edison

Con Edison has a general provision for Buyback Service that provides it the right to refuse or limit the amount of capacity and energy it will take from Buyback Service customers "where engineering considerations dictate that such actions are reasonable."[13] Con Edison's tariffs specify that a capacity

[12] Case 20-E-0373, Central Hudson Gas & Electric Corporation - Tariff Filing, Order Approving Tariff Filing (issued November 24, 2020).

[13] Consolidated Edison Company of New York, Inc. - Schedule for Electricity Service - PSC NO: 10 – Electricity, leaf 461.

seller with a generating facility sized at 5 MW or less may elect to sell its capacity to the utility and receive payments based upon the NYISO unforced capacity monthly market price applicable to such capacity.

National Grid

National Grid's tariffs specify that it will purchase capacity from qualifying producers of energy. For purchase contracts executed on or after July 1, 2019, capacity to be purchased is the lesser of the amount, in kilowatts (kW), of the UCAP recognized by the NYISO as applicable to capacity requirements for the respective calendar month, as set forth in the NYISO tariff, or 5 MW. The monthly UCAP is multiplied by the monthly Locational Based Marginal Capacity Price (LBMCP) to determine UCAP compensation.[14]

NYSEG and RG&E

NYSEG and RG&E Buyback Service tariff provisions specify that capacity purchases for each project shall be limited to 5 MW, except for customers with a contract in effect prior to July 1, 2019. NYSEG and RG&E determine the capacity payments by multiplying the Market-Clearing Price of Capacity, in $/kW-month (as determined from the NYISO's monthly UCAP auction), by the facilities' UCAP, in kW, as recognized by the NYISO (applicable to capability requirements for the respective calendar month, as set forth in the NYISO Tariff).

O&R

O&R's Buyback Service tariff provisions provide for the purchases of capacity and energy from generators sized at 5 MW or less. Like Con Edison, O&R can refuse or limit the

[14] The LBMCP is defined as the NYISO monthly Rest-of-State Installed Capacity Spot Market auction clearing price for the respective calendar month, in $/kW-month for capacity in each of the respective zones.

amount of capacity and energy it will take from Buyback Service customers based on engineering considerations. O&R compensates for UCAP based on the NYISO unforced capacity monthly market price applicable to such capacity.

NOTICES OF PROPOSED RULE MAKINGS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemakings (Notices) were published in the State Register on October 30, 2019 [SAPA Nos. 15-E-0751SP25, 15-E-0751SP26, 15-E-0751SP27, 15-E-0751SP28, and 15-E-0751SP29]. The time for submission of comments pursuant to the Notices expired on December 30, 2019.

Moreover, in a Notice Announcing Standby Rate Design Stakeholder Forum and Soliciting Comments, issued November 5, 2019, comments were solicited by January 13, 2020. In the Notice Extending Comment Period Related to Allocated Cost of Service Studies, and Standby and Buyback Rates, issued December 24, 2019, the comment period was extended to February 28, 2020. The Notice Scheduling Reply Comment Period and Soliciting Additional Input, issued February 27, 2020, sought reply comments by March 30, 2020, in response to the initial comments submitted on the Joint Utility Filings.

The notice issued on February 27, 2020, also requested each of the Joint Utilities to file, by March 16, 2020, descriptions of the procedures and requirements which Buyback Service customers must follow to sell capacity services to the utilities. Comments related to these filings were requested by April 13, 2020.

COMMENTS

In response the notices indicated above, various comments were filed regarding 1) the cost allocation methodology

for Standby Rate development and 2) Buyback Service rates. These comments are summarized and addressed below.

Blueprint Power Technologies, Inc.

Blueprint Power Technologies, Inc. (Blueprint) explains that Con Edison, O&R, NYSEG, RG&E, and Central Hudson require Buyback customer to be a NYISO-registered MP to sell capacity to the utility. Blueprint claims that this requirement is overly burdensome, and the utilities should allow an aggregator to fulfill such requirement on behalf of customers. Blueprint claims that there is a precedent for such practice and points to the NYISO rules that allow registered aggregators to participate in the ICAP Special Case Resources (SCR) program on behalf of the individual SCRs.

The City of New York

The City of New York (City) submitted comments on Con Edison and O&R's procedures for Buyback customers to sell capacity services to the utilities. The City requests that the Commission reject Con Edison's procedures because "they frustrate the Commission's intent to offer Buyback Service customers a meaningful choice between selling their [UCAP] to Con Edison or the [NYISO]."[15] The City explains that Con Edison's procedures for Buyback customers to sell capacity to Con Edison requires those customers to meet all the same requirements that the NYISO imposes for capacity sales. According to the City, this means there is no "meaningful difference between the NYISO's requirements and the [Con Edison procedures]."[16] The City contends that National Grid's capacity sale provisions contain "less onerous requirements and procedures that better conform to the Commission's objective of

[15] City Comments (filed on April 13, 2020), p. 1.

[16] City Comments, p. 2.

offering buyback customers a viable option for the sale of capacity."[17] The City requests that the Commission reject Con Edison's procedures and direct Con Edison to implement procedures similar to those of National Grid.

Consumer Power Advocates

Consumer Power Advocates (CPA) filed comments regarding Con Edison and O&R's Buyback Service procedures and requirements. CPA noted that NYSEG, RG&E, and Central Hudson have Buyback Service procedures and requirements that mirror those of Con Edison and therefore their comments extend to those companies as well. CPA claims that Con Edison's revised language concerning NYISO requirements shifts the burden from the requirement that the capacity meet all the NYISO requirements applicable to installed capacity to the customer needing to meet all such requirements. CPA contends that this shift "vastly increases the burden imposed on customers who would seek to obtain capacity revenues from the Company" which CPA argues conflicts with the Commission's intentions.[18]

CPA explains that Con Edison's revised procedures require generators that want to sell capacity to the company to: 1) join the NYISO as a MP; 2) register the resource(s) with the NYISO as an installed capacity resource; 3) meet all the associated requirements to certify the resource as a capacity provider and certify its capacity in UCAP terms; and 4) transfer the UCAP to Con Edison via the NYISO's monthly capacity certification form. CPA claims these requirements are burdensome and will dissuade most customers from participating in utility purchase of capacity. CPA asserts that direct participation in the NYISO capacity market requires a monumental

[17] Id.

[18] CPA Comments (filed April 13, 2020), p. 4.

effort and there are very few such participants. CPA provides a lengthy list of requirements for becoming a certified MP which is necessary for direct participation in NYISO capacity markets. CPA posits the requirement will likely require a dedicated staff person and may result in operational requirements that are inconsistent with the dispatch of the facility for the host customer's needs. CPA maintains that NYISO certification of capacity is unnecessary.

CPA explains that National Grid uses the same approach as the NYISO for converting ICAP to UCAP and that "National Grid is able to ensure that there is no inconsistency between what it pays the buyback customer for capacity and what it saves by not purchasing capacity on behalf of its full-service customers."[19] CPA asserts that the Aligned Utilities reliance on the 2019 Standby Rate Order to support their procedures is misplaced and recommends that the Commission reject the Aligned Utilities buyback approach and instead require all utilities to treat buyback purchases of capacity as load modifiers.

Digital Energy Corp.

Digital Energy Corp. (Digital) states that participating in the NYISO power markets as a MP imposes complex and burdensome requirements that are especially onerous for small generators. Digital notes that five of the six Joint Utilities require customers wishing to sell capacity to the utilities to become a NYISO MP. Digital claims this NYISO MP requirement violates the Commission's directive to "eliminate or reduce barriers to deployment of DERs."[20] Digital requests the Commission order the Joint Utilities to use the energy and

[19] CPA Comments, p. 13.

[20] Digital Comments (filed April 13, 2020), p. 2.

capacity values as defined in the Value of Distributed Energy Resources (VDER) Value Stack for Buyback Service customers.

Digital also notes there are structural problems with the utilities' buyback compensation procedures. For example, Digital questions how DERs that do not meet the NYISO Behind-the-Meter Distributed Generation minimum of 2 MW with at least 1 MW of host load can participate in the utilities' Buyback Service. Digital explains that DERs under 1 MW of capacity are not allowed to offer into the NYISO capacity market unless doing so as a Responsible Interface Party that participates as a SCR. Digital adds that Buyback customers are not SCRs. Additionally, Digital states that it is unclear who would bid/schedule/notify the NYISO DER resource and how that information would be communicated to a Buyback customer. Finally, Digital questions who would be responsible for penalties in the event a utility-caused outage precludes the resource from delivering energy to the distribution system. Digital requests that the Commission make UCAP payments under Buyback Service consistent with VDER compensation.

LEGAL AUTHORITY

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

preservation of environmental values and the conservation of natural resources."

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

DISCUSSION

The September 2019 Tariff Filings proposed by the Joint Utilities are generally consistent with the Commission's directives in the 2019 Standby Rate Order. However, there are several areas of inconsistency that should be reconciled as discussed below.

Mass Market Customer Standby Service Issues

1. Super-Peak Period Applicability

The Commission has commented on the potential for Standby rates to align individual customers' contribution to system costs with the rates such customers pay. As such, Standby rates can send improved price signals to customers as compared to traditional rates. In the 2019 Standby Rate Order, the Commission found the accuracy of these price signals will be improved if the utilities were to offer more granular Daily As-Used Demand Charges. The Commission therefore required the Joint Utilities, other than Con Edison, to "start the process of

implementing more granular Daily As-Used Demand charges."[21] The more granular As-Used Demand Charges were to include Off-Peak, On-Peak, and Super-Peak charge components.

Con Edison was exempt from this requirement because it already has an optional Standby Rate Pilot, known as Rider Q, in effect. Pursuant to Rider Q, Standby service customers (taking service under SCs 5, 8, 9, 12, or 13 or P.S.C. No. 12 - Schedule for Power Authority of the State of New York (PASNY) Delivery Service) can opt into Locational Variant Daily As-used Demand Pricing, which includes a Super-Peak period based on the four-hour call window for the peak-shaving CSRP Dynamic Load Management program applicable to each area of Con Edison's service territory. Rider Q significantly improved time-varying price signals for customers by establishing Super-Peak periods that aligned with Con Edison's CSRP call windows by network.

In the September 2019 Tariff Filings, Central Hudson, Con Edison, and O&R proposed that residential Standby Service customers would not be subject to Super-Peak Daily As-Used demand charges. All other customers would be subject to Super-Peak Daily As-Used Demand Charges, including small commercial customers. National Grid, NYSEG, and RG&E proposed all Standby Service customers be subject to Super-Peak Daily As-Used demand charges.

Residential customers that opt into Standby Service are likely to be above average energy users that have either DERs, heat pumps, or electric vehicles that will be charged at the residence. These residential customers may have greater energy consumption and demands than many small commercial customers. We find that assessing Super-Peak Daily As-Used Demand Charges to residential Standby Service customers is

[21] 2019 Standby Rate Order, p. 33.

appropriate to send improved price signals to the customers most likely to opt into Standby Service. Con Edison, O&R, and Central Hudson are therefore directed to include Super-Peak Daily As-Used Demand Charges for residential Standby Service customers in their revised draft tariff filings.

2. As-Used Demand Rate Structure

First, each of the Joint Utilities proposed to differentiate applicability of Super-Peak As-Used demand charges by seasons. Each of the Joint Utilities specified that Super-Peak As-Used demand rates during the summer would be applied for the months of June, July, August, and September. In addition, NYSEG proposed a winter Super-Peak period. Since NYSEG has had similar summer and winter system demand peaks, its proposal to apply Super-Peak As-Used demand rates during the winter is appropriate.

The Joint Utilities developed their Daily As-Used On-Peak and Super-Peak Demand rates using a variety of methods. For example, Central Hudson developed its Super-Peak Daily As-Used Demand rates by dividing 15 percent of the class-specific Daily As-Used Demand revenue requirement by the billing determinants for the Super-Peak period; 15 percent was determined from the ratio of Central Hudson's peak demand (summer) to the average of its peak demand experienced in the summer and winter periods. Con Edison developed Daily As-Used Demand rates for the summer and non-summer months based on the existing summer/non-summer revenue relationship for residential customers; and, based on the current summer/non-summer rate relationship for all other classes. National Grid developed its Daily As-Used Demand rates such that approximately 60 percent of Daily As-Used Demand Charge revenues are recovered though Daily As-Used On-Peak Demand Charges with the remaining 40 percent recovered in Daily As-Used Super-Peak Demand Charges. NYSEG and

RG&E designed Daily As-Used Demand rates such that the ratio of Daily As-Used Demand Super-Peak rates to Daily As-Used Demand On-Peak rates is two to one. For NYSEG, approximately 50 percent of the revenues are allocated to Daily As-Used Demand On-Peak Charges and 50 percent of the revenues are allocated to Daily As-Used Demand Super-Peak Charges. For RG&E, approximately 60 percent of the revenues are allocated to Daily As-Used Demand On-Peak Charges and 40 percent of the revenues are allocated to Daily As-Used Demand Super-Peak Charges. As described earlier, O&R developed its Super-Peak Daily As-Used Demand rates to recover a certain percentage of the transmission revenue requirements from the applicable service class (i.e., for secondary classes 50 percent of transmission revenue requirement was allocated to the summer Super-Peak rate and for primary classes 25 percent of the transmission revenue requirement was allocated to it in the summer Super-Peak rate).

The development of Super-Peak Daily As-Used Demand rates is in an early stage of development, and we find that none of the proposed methods is clearly preferable over the others. Each of the utilities' proposals were developed in a rational manner to reflect circumstances specific to their systems. While there are differences, each of the utilities' proposals appear reasonable and need not be modified at this time.

3. Determination of Demand for Mass Market Standby Customers

For demand-billed service classifications, each of the Joint Utilities determine a customer's demand using an integrated demand method. Integrated demand is determined by dividing the amount of energy consumed, in kilowatt-hours (kWh), over a specified interval by the duration of the measurement interval (in hours). For example, if a customer uses 100 kWh of energy over a 30-minute period (or 0.5 hours) the integrated demand would be 200 kW. If a customer uses 100 kWh of energy

over a 60-minute period (or one hour) the integrated demand would be 100 kW. As illustrated, increasing the interval over which demand is determined dampens any short-term spikes in measured demand.

The Joint Utilities recommend a variety of integration intervals. For residential customers, Central Hudson, Con Edison, and O&R propose to measure 60-minute integrated demands, while NYSEG and RG&E propose to measure 30-minute integrated demands, and National Grid proposes a 15-minute interval. For non-residential customers, including the small commercial non-demand portion of mass market customers, Con Edison, NYSEG, and RG&E propose to measure 30-minute integrated demands, whereas Central Hudson, National Grid, and O&R propose to measure 15-minute integrated demands.

The Commission finds that a 60-minute integration interval is appropriate for mass market customers, including both residential and small commercial, that would otherwise be served under a non-demand billed service classification. In determining the measurement interval for mass market customers, the Commission must consider the anticipated level of sophistication of customers within the classes and develop rates and requirements that will balance accuracy of the price signals customers are expected to respond to with the customers' ability to respond to such signals. While mass market customers may develop more price-responsive behaviors as new technologies and automation procedures are adopted, we find that it is inappropriate to adopt a granular approach at this time. Therefore, the Commission directs the utilities to implement 60-minute integrated demand measurements for mass market customers that would otherwise be served under a non-demand billed service classification in their draft tariff filings.

Billed demand is not only impacted by the duration of time over which integrated demand is measured, but also by the frequency of measurements. For example, 60-minute integrated demand could be measured once per hour, or it can be measured in rolling intervals. As with the integrated demand interval, increasing or decreasing the frequency of measurements can also change how sensitive the measured demand is to short term spikes. Increasing measurement frequency results in demands that are more sensitive to short term spikes, whereas less frequent measurement results in demand that is less sensitive to short term spikes. In practice, the utilities generally measure integrated demand in rolling intervals every 15 minutes. However, the frequency at which integrated demand would be measured was not specified in the utilities' September 2019 Tariff Filings. Therefore, the draft tariffs are to specify what intervals will be used when establishing integrated demand for Standby Service customers.

4. Establishment of Contract Demand

Each of the Joint Utilities has slightly different provisions regarding the initial establishment of Contract Demand for mass market Standby customers. Central Hudson specifies that Contract Demand will be initially set at the maximum metered demand over the previous 12 months for customer with 12 months of metered demand history. Con Edison and O&R specify that the Contract Demand will be initially established based on the customer's monthly maximum demand, up to the most recent 24 months. National Grid specifies that Contract Demand will be initially established as the customer's maximum measured demand during the first billing period. NYSEG and RG&E use the metered demand for the billing month of the first Standby Service bill to establish the initial Contract Demand. All the

utilities increase Contract Demand if a customer's As-Used demands surpasses its Contract Demand.

However, the utilities meter demand over intervals that are shorter than the interval for which they will bill demands for mass market Standby Service customers. For example, most of the utilities meter demand in 15-minute intervals. However, the utilities will be using 60-minute intervals to determine Daily As-Used demand for mass market Standby service customers. Central Hudson, National Grid, NYSEG, and RG&E are to revise their provisions with respect to the initial determination of Contract Demand for mass market customers such that Contract Demand is determined consistently with the way demand will be billed for these customers.

Buyback Rate Issues

1. Incremental Contract Demand Charge for Dual Service Customers

The 2019 Standby Rate Order required National Grid, NYSEG, and RG&E to design "rates for dual-service customers to include an incremental Contract Demand charge for generator capacity kW greater than the customer's maximum annual usage demand."[22] Con Edison, Central Hudson, and O&R have tariff provisions that require them to assess a Contract Demand Charge for Buyback Service demand that is greater than the demand served under the buyback customer's other service classification. Central Hudson applies the Buyback Contract Demand rate to the amount of generation capacity that exceeds the maximum annual demand billed under the customer's other service classification. Con Edison applies the Buyback Service Contract Demand rate to the customer's Buyback Service Contract Demand in excess of: 1) the Contract Demand if billed under

[22] 2019 Standby Rate Order, p. 46.

Standby Service; or, 2) the monthly demand billed under another rate if not billed under Standby Service. O&R establishes the initial Contract Demand for Buyback Service customers by subtracting the maximum billing demand used by the customer during the last 12 months immediately preceding commencement of Buyback Service from the nameplate capacity of the customer's generation facility.[23]

For a dual service customer, NYSEG and RG&E propose to assess the Contract Demand rate on the generated capacity that is greater than the customer's maximum annual usage demand. National Grid proposes to assess the Contract Demand rate to the kW amount of the customer's generation nameplate capacity that exceeds the Contract Demand that would be set as if the customer were taking Standby Service.

We find Con Edison's approach to be superior as it is the most cost-reflective for dual service customers. Traditional demand rates mingle recovery of Shared and Local costs, and in most cases even Customer costs (if customer charges are not commensurate to customer related costs), within the same demand rate that is assessed on maximum monthly demand. However, both Standby and Buyback Service rates include a Customer Charge and a Contract Demand Charge. The purpose of the Buyback Service Customer Charge, where applicable, and Contract Demand Charge is to ensure that each customer pays their share of the Customer and Local costs that are incurred as a result of their use of the grid. Contract Demand rates are assessed on the highest demand a customer places on the system, as opposed to the monthly demand that the customer places on the

[23] If the Buyback Service customer has not been taking service for a full year prior to commencing Buyback Service, O&R will estimate the maximum annual demand of a customer's facilities excluding the customer's generation facilities.

system. Con Edison's methodology ensures that a Buyback customer that is using an exemption from Standby Service, and instead chooses to be billed under traditional demand rates, will adequately contribute toward their share of Local costs during months in which their billed demand under traditional demand rates is lower than what their Contract Demand would have been. We therefore require the other utilities to include revisions in their draft tariffs to conform with the Con Edison methodology.

UCAP 5 MW Purchase Requirement

In the 2019 Standby Rate Order, the Commission established a maximum 5 MW "project-limit" for utility purchases of UCAP. The Joint Utilities have different interpretations of the "project-limit." Tariff provisions for National Grid, NYSEG, and RG&E specify that utility purchases for each project shall be limited to 5 MW, except for Buyback customers that had existing UCAP purchase contracts prior to the effective date of the revised tariffs. Additionally, Central Hudson's inadvertently deleted provisions were similar in nature to those of National Grid, NYSEG, and RG&E. Con Edison and O&R have provisions that specify the companies will purchase UCAP from generation facilities with a nameplate rating of 5 MW or less.

There is a notable distinction that National Grid, NYSEG, and RG&E limit the purchase quantity of UCAP at 5 MW while Con Edison and O&R limit the generators from which they will purchase UCAP based on the nameplate rating of the generator. For example, National Grid, NYSEG, and RG&E have provisions that allow for the purchase of 5 MW of UCAP from a generation facility that has a nameplate rating above 5 MW. Conversely, the Con Edison and O&R provisions preclude such a purchase. By this Order, we clarify that the 5 MW purchase limit is applicable to the amount of UCAP being purchased and is

not based on the generator's capacity or nameplate rating. Con Edison and O&R are directed to revise their tariff provisions accordingly.

Additionally, Central Hudson is directed to file a tariff revision to its Buyback Service on not less than five days' notice, to become effective on April 1, 2022, that reinstates the tariff provisions that were inadvertently deleted. This tariff revision is to specify that the maximum UCAP purchase under Buyback Service will be 5 MW; and, facilities with contracts established prior to July 1, 2019, are exempt from the 5 MW UCAP purchase limit. The Commission will waive the requirements of newspaper publication with respect to this tariff revision as it has already been the subject of public notice and is merely reinstituting a provision that was erroneously removed.

1. Market Participant Requirement for UCAP Compensation

The Aligned Utilities require Buyback Service customers to become a MP with the NYISO to be eligible to sell UCAP to the applicable utility. As the Aligned Utilities claim, UCAP is a defined and tradable product in the NYISO market. Requiring Buyback Service customers to become a MP enables the NYISO to determine how much UCAP the Buyback Service customer's generation resource is eligible to supply based on the type of generation and the generator's specific historical forced outage rate. This requirement provides UCAP compensation to Buyback Service customers that closely correlates to the Aligned Utilities' avoided cost.

However, as noted by Blueprint, the City, CPA, and Digital, participating in the NYISO power markets as a NYISO MP is a complex process and imposes burdensome requirements on small generation facilities. Digital suggests that the Commission direct the Joint Utilities to use the VDER Value

Stack capacity component alternatives instead of their current procedures. Under the VDER Value Stack tariff provisions, there are three alternatives for capacity compensation. Alternatives one and two are available only to intermittent DERs (like solar and run-of-river hydropower). Alternative one provides for capacity value compensation using solar PV load curves to estimate the likely ICAP contribution from the "fleet" of distributed intermittent generation in an ICAP region multiplied by published NYISO monthly prices. The capacity value is divided by the estimated number of kWh that value should be spread over to develop the Capacity Value $/kWh credit for each month. Alternative two divides the capacity value, in $/kW, of the estimated generation over the 240 – 245 hours during which the system peak will likely occur each summer.[24] The $/kWh value for Alternative two is higher than that of Alternative one, but payments are made over fewer hours. Finally, Alternative three compensates distributed generators based on the quantity of injections during that NYCA peak hour. Alternative three, often referred to as the "capacity tag" approach, is mandatory for dispatchable DERs and energy storage.

Alternative three provides the most precise capacity compensation, as current utility ICAP costs are most precisely caused by consumption that occurs during the NYCA peak hour. We agree, as stated by Digital, that using the VDER Value Stack Capacity Component Alternatives provide a simpler capacity compensation for DERs. As such, the Joint Utilities shall allow VDER Value Stack Capacity Component Alternatives for dispatchable DER under Alternative three compensation which negates the proposed requirement that buyback customers become

[24] The 240 - 245 summer hours includes the hours of 1:00 p.m. through 6:00 p.m. on weekdays (excluding holidays) between June 24 through August 31.

MPs. Non-dispatchable DERs (i.e., solar, wind, run-of-river hydro, and tidal) shall be provided the option of being compensated using any of the three VDER capacity compensation alternatives, at the discretion of the generator.

2. Exception for 5 MW Limit on Required UCAP Compensation

In the 2019 Standby Rate Order, the Commission specified that the 5 MW UCAP purchase limit would not apply to non-Value Stack eligible generators that had UCAP purchase contracts in effect prior to the effective date of the revised tariff provisions. By this Order, we clarify that the exception applies to the facility, not to the contract or the customer (facility owner). If UCAP purchase contracts are renewed for these exempted facilities, the compensation methodology is to follow the VDER capacity compensation alternatives described above.

CONCLUSION

The draft tariff revisions directed by this Order maximize consistency of the Joint Utilities Standby Service and Buyback Service tariff provisions to the extent practicable. Further, the revisions to the Buyback Service tariff provisions will remove barriers for DERs by providing for a simpler capacity compensation method. The Joint Utilities are directed to file further revisions to the draft Standby Service tariffs, as well as draft revisions to current Buyback Service tariff provisions, as described in detail above, within 120 days of the issuance date of this order.

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, Rochester Gas & Electric Corporation, and Orange and Rockland Utilities, Inc. are directed to file draft Standby Service tariffs and Buyback Service tariff provisions, as described in detail in the body of this Order. The draft tariffs are to include rates that are designed using the Allocated Cost of Service methodology adopted by the Commission in the companion order being issued contemporaneously in this proceeding, as well as updated inputs as described in the body of this Order. The draft tariffs are to be filed within 120 days of the issuance date of this Order. Specifically:

a. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc. are to include Super-peak Daily As-Used Demand Charges for residential Standby Service customers in their revised draft tariff filings.

b. 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, Rochester Gas & Electric Corporation, and Orange and Rockland Utilities, Inc., are directed to implement 60-minute integrated demand measurements for mass market customers that would otherwise be served under a non-demand billed service classification in their draft tariff filings.

c. 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, Rochester Gas & Electric Corporation, and Orange and Rockland Utilities, Inc. are directed to specify

what intervals will be considered when establishing integrated demand for Standby Service customers.

d. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Rochester Gas & Electric Corporation, are to establish the initial Contract Demand for mass market customers consistent to the way demand will be billed for these customers.

e. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Rochester Gas & Electric Corporation, and Orange and Rockland Utilities, Inc. are directed to modify the establishment of Contract Demand for dual-service customers to be consistent with the methodology utilized by Consolidated Edison Company of New York, Inc.

f. Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. are directed to establish a 5 megawatt unforced capacity purchase limit that is applicable to the amount of unforced capacity to be purchased, as opposed to the capacity or nameplate rating of the generation unit from which Unforced Capacity is being purchased.

g. 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, Rochester Gas & Electric Corporation, and Orange and Rockland Utilities, Inc. are directed to purchase unforced capacity under Buyback Service using the

Value of Distributed Energy Resources Value Stack Capacity Component Alternatives and shall not require Distributed Energy Resources selling such capacity under Buyback Service to become Market Participants within the New York Independent System Operator, Inc.

2. Central Hudson Gas & Electric Corporation is directed to file revisions to its Buyback Service tariff on not less than five days' notice, to become effective on April 1, 2022, that reinstates the tariff provisions specifying that the maximum Unforced Capacity purchased under Buyback Service will be 5 megawatts, and that facilities with contracts established prior to July 1, 2019, are exempt from the 5 megawatt purchase limit.

3. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1 as to newspaper publication of the tariff revisions in Clause No. 2 are waived.

4. 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.

5. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary