STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

ORDER REGARDING VALUE STACK COMPENSATION

Issued and Effective: April 18, 2019

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on April 18, 2019

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Gregg C. Sayre
Diane X. Burman, dissenting
James S. Alesi

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BY THE COMMISSION:

INTRODUCTION

On March 9, 2017, the Public Service Commission (Commission) issued the VDER Transition Order, which enabled the transition to a distributed, transactive, and integrated electric system by compensating distributed energy resources (DERs) based on the actual value provided by those resources.[1] The VDER Transition Order was followed by the VDER Implementation Order, which provided the details needed to produce actual, effective tariffs based on the Value Stack

[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).

compensation method developed in the VDER Transition Order.[2] Both Orders acknowledged that the Value Stack as established in those Orders was an initial, transitional tariff that would require further development.

Pursuant to instructions in the VDER Transition Order, Department of Public Service Staff (Staff) convened a Value Stack Working Group to improve the calculation and compensation methodologies used for the Value Stack. On December 12, 2018, Staff filed the Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs (Compensation Whitepaper). On December 14, 2018, Staff filed the Whitepaper Regarding Capacity Value Compensation (Capacity Value Whitepaper; collectively with the Compensation Whitepaper, the Staff Whitepapers). The Staff Whitepapers propose a number of modifications to the Value Stack and related compensation rules, including how the Demand Reduction Value (DRV) and Capacity Value are calculated. The Staff Whitepapers were the culmination of an extensive stakeholder process to consider refinements to the Value Stack and related policies.

The Compensation Whitepaper reflects a final version of the recommendations initially described in Staff's Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (Draft DRV Whitepaper), as well as recommendations in Staff's Whitepaper on Future Community Distributed Generation Compensation (CDG Whitepaper), both filed on July 26, 2018. The Capacity Value Whitepaper presents Staff's recommendations related to refinements in the Capacity Value component of the Value Stack.

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[2] Case 15-E-0751, supra, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) (VDER Implementation Order).

This Order adopts Staff’s recommendations in the whitepapers with modifications. The decisions in this Order improve the predictability, transparency, and accuracy of DRV, Locational System Relief Value (LSRV), and Capacity Value calculation and compensation. In addition, it authorizes a new Community Credit and related incentives to encourage robust CDG development. Specifically, the Order includes the following: (1) DRV calculation changes to reflect performance during a larger set of hours and to lock-in the value for ten years; (2) the continuation of the LSRV, modified to compensate projects for performance during utility calls; (3) the expansion of Phase One Net Energy Metering (Phase One NEM) eligibility for certain additional projects under 750 kilowatts (kW); (4) the establishment of the Community Credit for certain CDG projects in the New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Rochester Gas and Electric Corporation (RG&E), and Consolidated Edison Company of New York, Inc. (Con Edison) territories as a replacement for the Market Transition Credit (MTC); (5) the provision of an upfront incentive as an MTC replacement, the Community Adder, for new CDG projects in the Central Hudson Gas & Electric Corporation (Central Hudson) and Orange and Rockland Utilities, Inc. (O&R) territories; (6) the modification of the Alternative 1 Capacity Value calculation to reflect published New York Independent System Operator, Inc. (NYISO) monthly prices and solar photovoltaic (PV) load curves; and (7) the modification to the Alternative 2 Capacity Value calculation to better reflect actual peak hours. The compensation rules for various project types following this Order are summarized in Appendix C.

BACKGROUND

The VDER Transition Order directed the transition of compensation for eligible DERs from NEM to the Value Stack for various rate classes and project types. The Value Stack is a methodology that bases compensation on the actual, calculable benefits that DERs create. DERs subject to the Value Stack receive compensation for the energy they inject into the utility system for a set of values calculated based on the utility costs they offset: Energy Value, based on the energy commodity purchase requirements offset by each kilowatt-hour (kWh) injected; Capacity Value, based on the Installed Capacity (ICAP) purchase requirements offset by injections; Environmental Value, based on the Renewable Energy Credit (REC) compliance cost offset by each kWh injected; DRV, based on the distribution costs offset by injections, averaged across the utility’s service territory; and LSRV, available only in locations that the utility has identified as having needs that can be addressed by DERs, and based on the higher, specific distribution costs offset by injections in that area.

The VDER Transition Order also established a number of transitional mechanisms to moderate the changeover from NEM to the Value Stack for various customer classes and project types, including Phase One NEM, which includes a limited continuation of NEM-style compensation, and the MTC, which is an adder that allows the Value Stack to approach the previous level of compensation under NEM. Phase One NEM is currently available only to certain residential and small commercial customers with DERs onsite. Commercial customers who are on a demand-based rate plan are presently ineligible for Phase One NEM for any new onsite distributed generation projects. Similarly, only residential and small commercial customers participating in CDG projects are potentially eligible for the MTC, whereas larger commercial customers are not eligible for the MTC but instead receive the DRV. Conversely, residential and small commercial customers who receive the MTC cannot also receive the DRV under present VDER policy.

The VDER Transition Order contemplated further refinements to the Value Stack and other related policies and identified a number of areas to be addressed in the “VDER Phase Two” process. The Commission included in the scope of VDER Phase Two “improvements and modifications to the VDER Value Stack, including components related to the bulk system, distribution system and societal values.”[3] Pursuant to this directive, Staff established the Phase Two Value Stack Working Group to engage stakeholders in this effort.[4]

SUMMARY OF WHITEPAPERS

After several working group meetings and extensive stakeholder input, Staff filed two documents on July 26, 2018: the Draft DRV Whitepaper and the CDG Whitepaper. Both whitepapers recommended, among other things, changes to Value Stack elements, including the DRV, LSRV, and the MTC. Staff explained in the Draft DRV Whitepaper that a final Whitepaper would be issued for formal comment and Commission consideration. Staff requested comments on the Draft DRV Whitepaper by August 27, 2018, and on the CDG Whitepaper by October 15, 2018. Subsequently, a notice of the CDG Whitepaper was published in the State Register consistent with the requirements of the State Administrative Procedure Act (SAPA), with comments pursuant to that notice due by October 22, 2018.

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[3] VDER Transition Order, p. 137.

[4] See Matter 17-01276, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack.

Following review of the comments from stakeholders on the draft DRV Whitepaper and the CDG Whitepaper, Staff determined that additional recommendations related to both whitepapers were appropriate. As a result, the Compensation Whitepaper was filed on December 12, 2018, and proposed modifications to VDER policies that are expected to improve the ability of the Value Stack to provide appropriate price signals and compensation so that developers and customers design and invest in projects that provide benefits to the electric distribution grid. Additionally, the proposed changes are expected to result in the development of hundreds of Megawatts (MW) of additional CDG projects in New York without increasing the potential non-participant impact previously forecasted.

In addition to the modifications included in the Compensation Whitepaper, Staff determined through stakeholder input and internal analysis that additional refinements were needed to the Capacity Value calculations in the Value Stack as well. The changes proposed in the Capacity Value Whitepaper, which was filed on December 14, 2018, are expected to increase the transparency, consistency, and accuracy of Capacity Value compensation under Alternative 1 and Alternative 2 of the Value Stack.[5] The whitepaper recommends changes to how the two capacity values are calculated to better reflect the true costs

[5] Most resources have three options in determining their Capacity Value compensation under the VDER Value Stack. Alternative 1 requires the utilities to select the capacity portion of the supply charge for a service class with a load profile most similar to a solar generation profile and use that supply charge to determine an annual capacity value for each kWh of generation. Alternative 2 is a variant of this method focused on the 460 peak summer hours, which generally occur during the 2 p.m. to 7 p.m. period. Alternative 3 uses a project’s assigned NYISO ICAP value, which is the mandatory option for dispatchable technologies and optional for other technologies.

and benefits that the eligible resource will provide to the electric grid. Furthermore, Staff recommends in the Compensation Whitepaper that the full set of proposed changes in both the Capacity Value Whitepaper and the Compensation Whitepaper be taken up by the Commission simultaneously so that all modifications to Value Stack compensation happen at the same time.

Compensation Whitepaper

Staff indicates in the Compensation Whitepaper that the current DRV and LSRV rules may represent an attempt to achieve greater granularity and precision than is reasonable and possible in an open, administratively-determined tariff mechanism. Staff further notes that the desire to compensate for precise grid values must be balanced with the risk that a more sophisticated tariff may result in price signals that do not fully incentivize and motivate developers and customers to make decisions based on the objective of maximizing grid value. In addition, Staff explains that the VDER tariff should be a supplement to, not an imitation of, the integrated planning, investment, and contracting process developed through the Distribution System Implementation Plan (DSIP) and Non-Wires Alternatives (NWAs) processes. However, Staff acknowledges that there is value to continuing a tariff-based process for smaller, intermittent facilities that cannot economically participate in utility NWAs given their unique characteristics and market segments.

Staff proposes in the Value Stack Compensation Whitepaper a new DRV methodology that is expected to provide more predictable and reliable compensation and, thereby, improve the ability of the Value Stack to spur development of large on-site and remote crediting projects. Staff proposes replacing the “de-averaged” DRV with the system-wide marginal cost estimates used generically for each utility's energy efficiency benefit-cost calculations, which would be updated no more frequently than every two years. Currently, the DRV is updated annually, consistent with the DSIP cycle, following the review and input process established for the biennial marginal cost study filings, and locked in for each project for a three-year period.

Staff proposes a new DRV methodology where the total $/kW-year would be assigned a $/kWh number to the peak summer hours of 1:00 PM to 6:00 PM on non-holiday weekdays from June 24 through August 31. This methodology will result in DRV compensation being spread over either 240 or 245 hours each year, which represents the summer hours that are the most likely to be candidates for the peak summer load hour. This change would increase predictability for developers by providing advanced knowledge of the specific hours and, as it spreads compensation over many more hours than the current 10-hour methodology, would substantially reduce uncertainty resulting from factors like weather. As the base value would change every two years, the $/kWh compensation would also change to follow that shift, but would be subject to a maximum adjustment of 5% in any direction in each two-year period. Staff recommends that projects that qualify after July 26, 2018, the date of publication of the Draft DRV Whitepaper, receive DRV compensation based on this new methodology.[6]

Projects using dispatchable DERs that prefer a smaller number of hours with a call signal should be permitted to opt out of receiving DRV and instead participate in the utility

[6] A project "qualifies" when it meets the standard for placement in a Tranche; that is, when it has a payment made for 25% of its interconnection costs or has its Standard Interconnection Contract executed if no such payment is required.

Commercial System Relief Program (CSRP), according to Staff.[7] The CSRPs are demand response programs that compensate resources for performing during an event, which is preceded by a call signal 21-hours in advance. Utilities will need to modify the rules of their CSRPs to permit resources to perform by injecting electricity into the distribution system, as the current rules are designed only for resources that reduce load, and to make any other necessary changes. While projects that have already qualified arguably should be grandfathered under the rules in place at the time they qualified, Staff recommends that existing DER be permitted to opt into either the new DRV methodology or CSRP participation. As with existing DRV rules, only customers not receiving an MTC are eligible for DRV compensation.

Staff also recommends in the Compensation Whitepaper that the LSRV should be phased out, with only existing qualified projects continuing to receive an LSRV. Any projects that can provide the specific functionality and performance requirements of either NWA or Demand Response (DR) programs will continue to be eligible to participate in those opportunities to receive compensation for the grid value they can provide. Staff recommends utilities be required to permit resources receiving Value Stack compensation to participate in such programs, though notes that in general this will require that those resources forego DRV compensation.

Staff further proposes that Phase One NEM be available for projects that: (a) have a rated capacity of 750 kW AC or lower; (b) are at the same location and behind the same meter as the electric customer whose usage they are designed to off-set;

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[7] Dispatchable DER resources have the ability to produce electricity when called upon, and therefore have more control to limit injections during peak periods when capacity costs are the greatest.

and (c) have an estimated annual output less than or equal to that customer's historic annual usage in kWh. This proposed change would apply at a minimum to all projects that qualify before January 1, 2020, for a 20-year term from each project's in-service date. Further, as these customers are, by definition, already subject to demand rates, Staff will consider whether this category of Phase One NEM should be modified as part of making its recommendations regarding a post-January 1, 2020 successor tariff for on-site mass market DER customers.

Staff modifies and replaces its recommendation in the CDG Whitepaper that Tranches 5 and 6 be established in NYSEG, National Grid, and RG&E territories with an MTC of $0.03/kWh and $0.025/kWh, respectively. Instead, projects in those utility territories qualifying after July 26, 2018, should receive a Community Credit of $0.0225/kWh, according to Staff. The Community Credit will differ from the MTC in that all members of the CDG project will receive it, rather than only mass market customers, and in that recipients of the Community Credit will also be eligible to receive DRV compensation. Eligibility for the Community Credit will be limited to the number of MW proposed in that territory for Tranches 5 and 6 in the CDG Whitepaper: 110 MW in NYSEG, 525 MW in National Grid, and 75 MW in RG&E.

The potential to lower project costs and increase participant benefits, while also lowering net revenue impacts, and therefore reducing non-participant impacts, also exists for CDG projects that have already been assigned a Tranche. Therefore, Staff recommends that one unified Community Credit value across all CDG projects in Tranches 1-4 is appropriate. Allowing non-mass-market customers that participate in those projects to receive a Community Credit at a level below the applicable MTC will encourage increased use of anchor customers and thereby reduce project financing costs, while also lowering total compensation for those projects and reducing net revenue impacts on ratepayers.

In addition, the value for CDG projects in Tranches 1-4 should be lower than the Community Credit value for new CDG projects because projects in Tranches 1-4 receive higher MTC compensation for mass market participants. Staff proposes a $0.01/kWh Community Credit value for non-mass-market participants of CDG projects in Tranches 1-4, to be applied in the same way and for the same period of time as the MTC for those projects. This recommendation applies to all CDG projects receiving the Value Stack and qualified for Tranche 1, 2, 3, or 4 in all utilities; it does not apply to projects receiving NEM or Phase One NEM (i.e., Tranche 0 projects), nor does it apply to new O&R and Central Hudson projects.

With respect to O&R and Central Hudson, Staff proposes in the Compensation Whitepaper that the recommendation from the CDG Whitepaper that new projects in their service territories receive only the base Value Stack as compensation, with an additional up-front incentive and with all customers receiving the DRV, not be modified.

For new projects in Con Edison’s service territory, Staff retains the CDG Whitepaper’s primary recommendation for a revised Tranche 1 with an MTC of $0.1435 applicable only to mass market customers. However, once the 128 MW allocated to the revised Tranche 1 are exhausted, Con Edison should be moved to the Community Credit model, with a rate to be determined in a Staff filing based at a level that maintains the 2% limit on incremental net revenue impact and that reflects the high level of DRV compensation in Con Edison’s territory.

Capacity Value Whitepaper

The Capacity Value Whitepaper discusses the experience with Capacity Value compensation over the first 12 months of Value Stack applicability and provides recommendations for improving Alternative 1 and Alternative 2 Capacity Value methodologies. Alternative 1, the default method, is based on the capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile and converts the service class's $/kW value into a $/kWh value with compensation at that value received for all generation during all hours of the year. Alternative 2 compresses the $/kW value into a higher $/kWh value with compensation at that value received for all generation during 460 summer hours to encourage project siting and design focused on peak summer hours. The 460 summer hours are 2:00 PM to 7:00 PM on every day from June 1 to August 31.

Staff discovered that some of the service class ICAP costs are hedged by their utilities and therefore they receive an all-in ICAP charge based on a mix of spot and hedged prices; other service classes are unhedged and simply are charged based on NYISO-reported ICAP prices (some monthly "spot" prices, others 6-month "strip" prices); while still others are hedged but the hedge component is assessed to customer bills as a separate rate element. In addition to this ICAP cost hedging distinction among utilities, it is clear that, even though the same method was used to select service classes, these do not necessarily reflect consistent values across the utilities in the Lower Hudson Valley (LHV) ICAP region.

Given the various inconsistencies between utilities, Staff proposed that a new, consistent method should be used for calculating Alternative 1 and Alternative 2 Capacity Values for projects receiving Value Stack compensation. Staff's proposed new method is to base Alternative 1 Capacity Value compensation on published NYISO monthly prices for the price element, using PV load curves provided by the New York State Energy Research and Development Authority (NYSERDA) to estimate the likely ICAP contribution from the “fleet” of distributed intermittent generation in an ICAP region and determine the number of kWhs that value should be spread over.

Regarding Alternative 2, Staff notes that the most important candidate hours for peak in the summer occur on non-holiday weekdays, from June 24 through August 31, during the hours of 1:00 PM through 6:00 PM. The number of those hours varies between 240 and 245 hours, depending on the year, and they present a significantly more accurate and more targeted approach than the 460 hours currently used for the Alterative 2 Capacity Value. Staff proposes to change Alternative 2 to focus on those 240-245 hours each summer, increasing the $/kWh value accordingly such that projects should receive essentially the same or better average compensation. Staff proposes that the $/kW-year value would be divided by the PV load shape’s estimated kWh for those 240-245 summer hours to derive Alternative 2’s $/kWh credit.

In the Capacity Whitepaper, Staff also asked for stakeholder feedback on a number of questions: (1) Did Staff select the correct load shapes? If not, what load shapes should be used? (2) If Staff’s (or a similar) approach is adopted, should it rely on NYISO monthly spot prices or NYISO 6-month strip prices? (3) Should projects that have already qualified be grandfathered? If so, should they be allowed to “opt in” to a new ICAP method, recognizing that MTC values were based on prior ICAP estimates? and (4) Is Staff’s selection of critical summer ICAP hours incorrect? If so, explain why and suggest a better alternative.

NOTICES OF PROPOSED RULE MAKING

Pursuant to SAPA §202(1), Notices of Proposed Rulemaking regarding the Staff Whitepapers were published in the State Register on December 26, 2018 [SAPA Nos. 15-E-0751SP19 and 15-E-0751SP20]. In addition, a Notice Soliciting Comments on Staff Whitepapers was issued on December 21, 2018.[8] The time for submission of comments pursuant to the Notice expired on February 25, 2019. Comments were received from over 25 stakeholders and over 30 members of the public. The comments received on the Staff Whitepapers are summarized in Appendix D.

LEGAL AUTHORITY

As described in the VDER Transition Order, the Commission has the authority to direct the treatment of DERs by electric corporations pursuant to, inter alia, Public Service Law (PSL) Sections 5(2), 66(1), 66(2), and 66(3). Pursuant to the PSL, the Commission determines what treatment will result in the provision of safe and adequate service at just and reasonable rates consistent with the public interest.

DISCUSSION

Following the implementation of the Value Stack, New York State has experienced robust DER development, including a record year for solar PV deployment in 2018 and enough projects in development to double distributed solar capacity. However, the Commission acknowledged that the Value Stack as established in the VDER Transition Order and VDER Implementation Order was an initial, transitional compensation mechanism and would

[8] The Secretary's Notice also requested comments on Staff's Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates, which was filed on December 12, 2018. That matter will be addressed at a future Session.

require further development. The VDER Transition Order directed Staff to convene a process to work on improvements to the Value Stack. A number of stakeholders raised concerns about certain elements of the Value Stack and recommended modifications, both within the Value Stack Working Group established by Staff and through other forums. The recommendations in the Compensation Whitepaper and Capacity Value Whitepaper are the culmination of a multi-year stakeholder process that included Value Stack Working Group meetings, including presentations, exchanges of written documents, and multiple sets of comments. The Staff Whitepapers present rational options for addressing those concerns and making other improvements to the Value Stack. Comments and further analysis suggest modifications to some of Staff's recommendations, as discussed below. The changes adopted in this Order will continue the evolution of the Value Stack to what the VDER Transition Order described as "Phase Two."

While the changes adopted in this Order are significant and address many of the concerns expressed by stakeholders and in comments, this Order is not intended to address all topics related to VDER. Activity continues to increase the availability of CDG to low- and moderate-income ratepayers, including through the Bill Discount Pledge program approved by the Commission[9] and through NYSERDA programs. The successor rate for mass market on-site distributed generation customers continues to be developed through the Rate Design Working Group. Finally, development of the Value Stack will continue following this Order, including review of the Environmental Value calculation methodology and whether that value can be made time-varying to reflect the impact of

[9] Case 15-E-0751, supra, Order Adopting Low-Income Community Distributed Generation Initiatives (issued July 12, 2018).

generation in reducing emissions at different points during the day and during the year.

Marginal Cost of Service Proceeding

Compensation for the portions of the Value Stack related to avoided distribution system costs, the DRV and LSRV, is based on the results of utility Marginal Cost of Service (MCOS) studies. Given the importance of these studies in the dynamically evolving utility systems, several utilities have made significant changes to the processes and methodologies for conducting them since the beginning of the Reforming the Energy Vision (REV) proceeding. Unfortunately, there has not been sufficient opportunity for meaningful external review of these new approaches. There are significant differences between how the MCOS studies are conducted at different utilities, which are even greater after these recent changes. Based on these variations and based on the significant decreases in resulting values at several of the utilities, it is clear that a thorough process is needed to examine the MCOS studies and determine what methodologies will lead to the most accurate results. This process must include opportunities for participation by stakeholders.

For those reasons, the Commission initiates a proceeding to examine MCOS studies and directs Staff to develop and issue a workplan and schedule for such a proceeding. As discussed below, current DRV and LSRV values are based on the last MCOS studies accepted by the Commission for use in VDER tariffs and will not be updated until that proceeding is complete and has resulted in new MCOS studies approved by the Commission.

Locational System Relief Value

A number of commenters disagreed with or expressed concerns regarding Staff’s recommendation that LSRV be phased out. The Commission agrees with commenters that, while issues may exist with the LSRV methodology, the development of locational price signals is an important component of VDER and that the alternatives discussed by Staff, including Demand Response programs and Non-Wires Alternatives, do not sufficiently meet the need to reflect locational value of distributed generation projects. LSRV offers an alternative more tailored to distributed generation than DR programs and more useful for utility needs that may not be appropriate for Non-Wires Alternatives (NWAs), due to size of the need or other factors. Rather than taking a step backward by eliminating the LSRV, the methodology should be modified to ensure that it offers meaningful price signals to incentivize and compensate projects that create actual locational value.

The primary issue with the effectiveness of the LSRV is the determination of relevant hours for compensation. Because LSRV compensation is based on hours determined after the fact, it is difficult for projects to take action to maximize LSRV compensation or to predict LSRV compensation.

To maintain alignment of the LSRV with actual system needs while increasing project owner’s ability to predict and manage LSRV compensation, and consistent with Staff’s discussion of the similarity to DR programs, LSRV compensation will be modified to use a call system, where projects eligible for an LSRV receive compensation for responding to utility calls. The existing total $/kW-year value for LSRV shall be divided by ten to determine compensation during each call window. Calls shall be made by the utility 21 hours in advance of the call window. An individual call window shall be between one hour and four hours long. Compensation for a call window shall be based on the lowest hourly net kW injection during the call window. Thus, if a call is for 3 hours and a project injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of that call, the project will be compensated for 1.5 kW at the per call window rate.

Each LSRV zone must have at least ten call windows per year to ensure that projects have the opportunity to earn the full LSRV. A utility may make calls in more than ten windows in an LSRV zone in a year. The compensation for such calls shall remain at the same level, such that the project has the opportunity to earn more than the total $/kW-year value assigned to the LSRV if more than ten calls are made. A project that fails to respond to a call shall not be subject to any penalty, other than not receiving compensation for that call window. Utilities shall use the same or similar call mechanism to that used for DR programs employing calls.

Furthermore, recognizing that peak hours almost always fall within certain windows and to further increase predictability for project owners, call windows generally must be within the DRV period for the utility territory and geographic area, as established below and shown in Appendix A, which also contains further calculation details regarding LSRV. As an alternative for LSRV areas with different peak hours than the system as a whole, each utility may group LSRV areas into up to four LSRV time groups with different 4-hour call windows, based on sub-system load peaks.[10] The $/kW-year LSRV shall be established when a project in an LSRV zone qualifies and that value and the applicable DRV period will be locked in for the first ten years of the project’s operation. Utilities may add LSRV zones at any time. Future identification and valuation of LSRV zones will be considered in the MCOS proceeding.

[10] With the exception of Con Edison, which already has four areas with different call windows.

These modifications will improve LSRV’s effectiveness in creating incentives for distributed generation developers and owners to design and operate their projects in ways that meet utility needs and will ensure that appropriate compensation is offered to projects that help offset costs in constrained areas of the distribution system. This LSRV will be most significant for dispatchable resources, particularly projects that include storage, but may also incentivize developers of intermittent resources like solar PV to design projects in a way that will maximize system value, such as through panel orientation or use of trackers.

Demand Reduction Value

The Compensation Whitepaper recommends a change in calculation of the base $/kW-year DRV to the total, average system-wide marginal cost estimates used for each utility’s energy efficiency benefit-cost calculations. Staff proposes this modification as a result of the proposal that LSRV be eliminated, since the original calculation of the DRV started with this number and then “de-averaged” it by removing portions of the marginal cost estimates assigned to LSRV zones. If the LSRV were eliminated, it would be appropriate to “re-average” the DRV by including those values. As the LSRV is being retained, this proposed change is no longer appropriate. Therefore, the $/kW-year DRVs established in compliance with the VDER Implementation Order, which are the average system-wide marginal cost estimates de-averaged to reflect LSRV, will continue to be used.

The Compensation Whitepaper noted that, as with LSRV, the use of generation during the top ten system hours, determined after the fact, for DRV compensation prevented developers from meaningfully predicting or managing DRV compensation and therefore prevented it from serving as an effective price signal or supporting development of projects. The Whitepaper proposed moving DRV compensation to a system similar to Capacity Alternative 2, with the $/kW-year DRV compensation divided between approximately 240 likely peak hours, 1:00pm to 6:00pm Eastern Daylight Time (EDT) between June 24 and August 31 inclusive, on weekdays excluding Independence Day.

Based on comments filed by the Joint Utilities and others, a further review was conducted of likely peak hours, based on actual peak load hours at each utility in recent years. The review determined that, for utilities other than Con Edison and NYSEG, relevant hours can be expected to fall between 2:00pm and 7:00pm EDT between June 24 and September 15 inclusive, on weekdays excluding Independence Day and Labor Day. For NYSEG, in addition to those hours, certain winter hours are also relevant: between 5:00pm and 7:00pm Eastern Standard Time (EST) between January 1 and January 31 inclusive, on weekdays excluding New Year's Day. For Con Edison, the relevant hours will continue to vary based on the zones used for CSRP. Each zone includes five hours each day between June 24 and September 15 inclusive, on weekdays excluding Independence Day and Labor Day. Appendix A shows the applicable hours for each zone. Appendix A also contains further calculation details for DRV and LSRV for all utilities. The $/kWh DRV rates for the relevant periods are determined by dividing the total $/kW-year DRV by the number of hours in the window.

To address another concern regarding the DRV, that it could vary too much within too short a period of time to be considered in project development, the Compensation Whitepaper recommended that the DRV $/kW-year value be adjustable every two years but with each adjustment limited to a maximum of 5% up or down. Commenters expressed concerns that, given the possibility for significant change in either direction as a result of methodological determinations made in the MCOS proceeding, this adjustment limit could result in a significantly overcompensatory or undercompensatory DRV for an extended period. For that reason, rather than bounded adjustments, a vintaging methodology shall be used. The DRV $/kW-year value and hours will be determined at the time a project qualifies, and locked-in for the first ten years of the project's operation. At the end of that ten-year period, the project will be transitioned to the then-applicable DRV rate and hours. The Commission notes that this use of a ten-year period, as opposed to the life-of-project or 25-year approach that has been used in other cases, may more accurately reflect development and financing decisions than those longer periods and should be considered for increased application as other aspects of the Value Stack are reviewed. The $/kW-year values established pursuant to the VDER Implementation Order and currently in the utilities' tariff statements will continue to be used for projects that qualify until new MCOS studies are developed and approved by the Commission as a result of the MCOS proceeding.

As an alternative to DRV and LSRV compensation, the Compensation Whitepaper recommends that projects be permitted to opt-in to participation in the CSRP portion of utility DR programs. While some commenters express concerns that the CSRP may provide less value than the DRV, it is certainly reasonable to offer it as a voluntary option. The utilities shall modify their tariffs as needed to offer this option, including modifying the CSRP tariffs and program rules to allow compensation for injections at the same rate as compensation for load reductions. Opting in to CSRP participation is a one-time, irreversible decision that may be made at any point during a project's Value Stack compensation term; however, to receive compensation for a particular CSRP period, the project owner must notify the utility of its intention opt in to CSRP consistent with the program's participation rules. To the extent that stakeholders believe that the CSRP is less compensatory than DRV for reasons not related to actual value, those stakeholders should raise those concerns in the DR proceeding, which includes annual updates and improvements to utility Demand Response programs.[11]

Phase One Net Energy Metering

As a transitional mechanism, Phase One NEM has been an attractive option for smaller DER projects that seek to avoid the complications resulting from the variable and time-dependent compensation inherent in the Value Stack. Phase One NEM, however, is no longer available for commercial customers with demand-metered accounts. Staff therefore proposes to expand the eligibility of Phase One NEM to those projects that: (a) have a rated capacity of 750 kW AC or lower; (b) are at the same location and behind the same meter as the electric customer whose usage they are designed to off-set; and (c) have an estimated annual output less than or equal to that customer's historic annual usage in kWh.

The proposal would apply at a minimum to all projects that qualify before January 1, 2020, for a 20-year term from each project's in-service date. Staff noted that it will consider whether Phase One NEM should continue for new projects only or should be modified as part of making its recommendations regarding a post-January 1, 2020 successor tariff for on-site mass market customers.

Almost all commenters, including the Joint Utilities, are supportive of Staff's recommendation. Multiple Intervenors

[11] Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs.

(MI) opposes the recommendation based on concern that it would impose costs on non-participating customers. PSEG Long Island (PSEG) notes that its tariff currently includes a similar limitation in terms of annual output for NEM projects of less than or equal to 110% of the customer's annual usage, allowing for customers to add projects that anticipate the customer's future growth needs.

The Commission adopts Staff’s recommendations. Staff, as supported by comments, demonstrates that this modification will cause no meaningful cost impacts in most cases as most eligible customers would not be able to avoid delivery costs. The Value Stack is a new compensation model, which as it evolves, may not be well-suited for use in all cases and market segments. Given the transitional nature of VDER Phase One, it is prudent to reflect on the viability of opportunities under VDER policy for smaller demand-metered non-residential customers that desire to offset their own usage with on-site DER technologies. These commercial customers, who may also want an option for more fixed compensation alternatives for DER projects, would receive compensation from NEM that are much more aligned with utility costs than non-demand-metered customers since the volumetric component of their rates are lower due to the applicability of demand charges. However, extending this recommendation to remote net metering and CDG, as recommended by the Alliance for a Green Economy (AGREE), would be inconsistent with the goals of VDER and could result in more significant cost shifts. The Commission also adopts PSEG’s suggestion that on-site load be less than or equal to 110% of the customer's annual usage, which will provide more flexibility on a customer's future growth needs than the 100% Staff recommendation.

Community Credit

The MTC was an effective tool for several purposes: to make initial compensation for CDG projects similar to net metering compensation, with a gradual shift away; to encourage participation of mass market customers in CDG; and to moderate the impact of the most variable element of the Value Stack, the DRV, by replacing it for a portion of the project. However, for these reasons, the MTC also disincentivized participation of large customers in CDG projects, which has the potential to increase project costs due to the financing and customer acquisition savings an anchor customer can create, and muted incentives for CDG projects to maximize their value to the electric grid by targeting the DRV. As master-metered apartment buildings are treated as large customers, it also made it difficult for tenants of those buildings to participate.[12] In addition, the distinction in MTC across utility territories, based on preexisting rates rather than actual benefits, resulted in more robust development in some areas than others without a basis in value.

The adoption of a Community Credit for new projects offers the opportunity to continue to stimulate robust CDG development with net revenue impacts within the 2% targets at each utility while addressing these flaws of the MTC. By expanding applicability to all CDG subscribers, the Community Credit will no longer discourage anchor customer or master-metered building participation. By adding to, rather than replacing, the DRV, the Community Credit will ensure projects

[12] This is contrary to Commission’s intention to facilitate participation of such customers in CDG, as demonstrated by the still-applicable rule that tenants in master-metered buildings be considered small customers for the purpose of the requirement that at least 60% of a project’s capacity be dedicated to small customers.

continue to have the incentive to maximize distribution system value. By having a consistent value across National Grid, NYSEG, and RG&E, the Community Credit will encourage development based on actual benefits and costs of a given location, rather than preexisting utility rates. The expected increase in participation of anchor tenants, as well as the other benefits of the Community Credit, also allow for the Community Credit to be set at a lower rate than an MTC to stimulate the same level of development, allowing for more projects to be funded while retaining the 2% target for net revenue impact. The requirement that 60% of a CDG project’s output be dedicated to small customers will ensure that most of the benefit of each CDG project still goes to residences and small businesses.

The Commission adopts Staff’s recommended Community Credit value of $0.0225/kWh for projects in NYSEG, National Grid, and RG&E. While some commenters argue the Community Credit should have a higher or lower value, the Commission has determined, based on existing development at various MTC levels, that $0.0225/kWh is an appropriate level to encourage continued robust development. Furthermore, as the proposed MW availability for the Community Credit is based on maintaining the 2% net revenue impact target at each utility, the Commission notes that a higher or lower Community Credit would result in less or more opportunity for development, respectively, rather than changing the net revenue impact. The Commission notes that approximately 15 MW of CDG projects at NYSEG and 5 MW of CDG projects at RG&E that had qualified for placement in a Tranche have been cancelled. For that reason, the Commission adopts Staff’s Community Credit availability recommendation as modified to reflect that additional available capacity, resulting in the following Community Credit availability in each service territory: 125 MW in NYSEG, 525 MW in National Grid, and 80 MW in RG&E. Appendix B shows the status of each utility following this Order.

As with the MTC Tranches, projects will reserve Community Credit availability when they qualify and will receive a Community Credit for 25 years following their in-service date. The utilities shall report on Community Credit availability in the same manner as they reported on MTC Tranche availability and shall file a letter with the Commission when 80% of the Community Credit capacity has been exhausted. If a project that qualifies for the Community Credit is later cancelled, its capacity shall be returned to the pool of Community Credit availability, as long as the Community Credit has not been fully exhausted. Where projects that were placed in Tranche 0-4 are cancelled, that capacity will not be re-opened. However, the Commission will continue to monitor such cancellations and may later use excess capacity created.

Staff also proposed a $0.01/kWh Community Credit for non-mass-market participants participating in CDG projects in Tranches 1-4. Several commenters note that this would result in increased compensation for projects that have already made development commitments and argue that this represents overcompensation. While it is true, as Staff notes, that in some cases this Community Credit may result in a project dedicating a greater percentage of its output to an anchor customer and thereby reducing overall costs, the Commission agrees that increasing available above-value compensation for existing projects creates a significant risk of increasing net revenue impacts without spurring additional development. For that reason, Staff's recommendation is rejected. For projects in Tranches 1-4, mass market subscribers will continue to receive an MTC at the established level and non-mass-market subscribers will not receive any credit above the Value Stack.

For Con Edison, Staff recommends the continuation of an MTC, at a higher level to encourage additional development. However, this would prevent developers in Con Edison from seeing the Community Credit benefits discussed above. Given the prevalence of apartment buildings in Con Edison's territory, the continued disincentive for including tenants of master-metered buildings would be particularly unfortunate. For that reason, the Commission adopts the Community Credit model for Con Edison as well. As this will result in cost savings and all customers receiving the DRV, the Commission adopts a Community Credit of $0.12, below Staff's recommended MTC level. To maintain the 2% net revenue impact target, the Community Credit in Con Edison will be available for 350 MW of CDG projects.

While some commenters express concern that the Community Credit will drive large customers to participate exclusively in CDG rather than remote crediting or on-site generation, the Commission believes that each situation will retain benefits and continue to be used in certain situations. Furthermore, by removing a disincentive for anchor customers, the Community Credit will create benefits by allowing the development of more projects at the same or lower net revenue impact. The increased use of anchor customers may also increase the ability of developers to enroll subscribers with low credit scores, as the anchor customer will provide the necessary certainty for financial institutions. The establishment of a level Community Credit and DRV applicability across utilities will also improve the simplicity of Value Stack compensation for new projects.

While the transition from the MTC to the Community Credit means that, for projects receiving the Community Credit, all subscribed generation will receive the same compensation, the Commission maintains the rule that unsubscribed generation, applied to the CDG project’s bank, will not receive above Value Stack compensation. For that reason, the Community Credit will not be included in compensation that is banked by the project rather than assigned to a subscriber. This will encourage project owners to promptly fill any empty capacity and avoid offering excessive incentives where credits are accumulated rather than used.

Up-Front Community Adder

As Staff explains, establishing any further MTC or Community Credit availability in Central Hudson or O&R would increase estimated net revenue impacts in those utility territories beyond the 2% target. Inasmuch as the MTC and the Community Credit principally represent the overall societal benefits of clean distributed generation and the role that generation has in meeting the State’s clean energy goals, the net revenue impact resulting from those payments should be spread across ratepayers to the extent possible, rather than concentrated on ratepayers in particular utility territories and service classes. Replacing the MTC with an upfront incentive from a statewide funding source, as proposed in the Compensation Whitepaper, is consistent with that goal. It will ensure continued development in Central Hudson and O&R while avoiding the potential for imposition of disproportionate costs on ratepayers at those utilities.

The Commission authorizes NYSERDA to fund a Community Adder incentive from previously collected, uncommitted ratepayer funds.[13] NYSERDA may spend up to $43,393,813 of such funds on this incentive. Consistent with Staff’s initial proposal for this incentive, projects that qualified prior to the issuance of this Order will receive a Community Adder reflecting the net present value (NPV) of a $0.03 per kWh MTC, reduced by estimated DRV compensation. For Central Hudson, this results in a Community Adder of $0.40 per Watt Direct Current (DC); for O&R, this results in a Community Adder of $0.25 per Watt DC. Projects that qualify after this date of the Order will receive a lower Community Adder rate, with Central Hudson project receiving $0.30 per Watt DC and O&R projects receiving $0.15 per Watt DC, reflecting the potential for further cost savings related to factors such as increased use of anchor customers. NY-Sun projects that receive a Community Adder will continue to be eligible to receive the available base incentive. Consistent with Staff’s proposal, this will provide funding for at least 50 MW Alternating Current (AC) of CDG in Central Hudson and at least 45 MW AC of CDG in O&R. If NYSERDA is able to fund more capacity than that with the stated budget, it shall offer incentives to additional projects in either utility territory until the budget is exhausted. Projects shall reserve their eligibility for this incentive at the time they qualify. NYSERDA shall provide transparent details on its website on the availability of the incentive. In addition, NYSERDA shall report on the use of these funds in its reporting on the NY-Sun program.

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[13] These uncommitted funds were collected through the Renewable Portfolio Standard (RPS) to achieve the goal of at least 25 percent of the electricity used in New York State being provided by renewable resources. The use of these funds to support development of CDG projects is consistent with the Commission’s stated goal in authorizing the collection of these funds.

Moving forward, as Community Credit availability is exhausted and to the extent that above-Value-Stack compensation continues to be needed to ensure robust development of CDG projects, it would be appropriate to consider extending the Community Adder to projects in other utility territories not receiving an MTC or Community Credit, as well as to extend its availability in Central Hudson and O&R. Any such extension would require further Commission consideration of funding source and incentive levels.

Alternative 1 Capacity Value

Staff's proposal to modify the Alternative 1 Capacity Value to employ actual, transparent NYISO capacity prices rather than opaque utility tariff calculations represents a meaningful improvement to the Value Stack. However, commenters identify several flaws in the details of Staff's proposal. Staff proposes that the Capacity Value credit be based on published NYISO monthly auction prices, with solar PV load curves used to: (1) estimate the likely ICAP contribution from the "fleet" of distributed intermittent generation in an ICAP region, based on expected performance on non-holiday weekdays from June 24 through August 31, during the hours of 1:00 PM through 6:00 PM EDT; and (2) determine the number of kWhs that value should be spread over.

First, commenters question Staff's proposal that the hours of 1:00 PM through 6:00 PM EDT be used. They note that, while those hours may appear the most likely to contain the peak hour based on an analysis of the last twenty years, a focus on more recent years illustrate that the peak is now more likely to be later in that timeframe rather than earlier, such that 2:00 PM to 7:00 PM EDT would be more appropriate. As discussed below, commenters also argue that this timeframe is appropriate for Alternative 2 Capacity Value compensation.

Second, commenters express concern with the solar PV load curves used for the calculation. They note inconsistent or counterintuitive results during certain hours.

Third, the Joint Utilities argue that the Alternative 1 rate calculation should use actual monthly kWh instead of the levelized monthly kWh since a levelized monthly kWh (equal to total annual kWh solar generation divided by 12) does not account for seasonal variation in solar output; it would therefore result in rates which are higher when monthly solar output is above average and lower when monthly solar output is below average. The Joint Utilities propose Alternative 1 compensation be based on monthly $/kW avoided ICAP costs divided by monthly kWh generation from the assumed profile, which varies by month based on seasonality.

All three of these criticisms have merit. The evidence that 2:00 PM to 7:00 PM EDT is a more accurate reflection of current peak hours is convincing. A review of the solar PV load curves shows that part of the data used for their generation failed to properly account for Daylight Savings Time. The utility analysis shows that inaccurate compensation would result from using levelized monthly kWh.

Therefore, the Staff recommendation is adopted subject to modifications. The calculation shall use the corrected solar PV load curves attached to this Order as Appendix E and should use the hours of 2:00 PM to 7:00 PM on non-holiday weekdays from June 24 to August 31 to determine the “proxy capacity factor” for the fleet of VDER resources eligible for Alternative 1 compensation. It shall also use the monthly kWh/kW shown in Appendix E, in combination with the actual monthly NYISO $/kW-month auction price, rather than the price from six-month strip auctions, as it most accurately reflects how ratepayers are charged for capacity. Thus, the monthly $/kWh compensation under Alternative 1 will equal the monthly NYISO $/kW-month auction price multiplied by the proxy capacity factor, divided by the monthly kWh/kW in Appendix E.[14]

Alternative 2 Capacity Value

Staff proposed changes to the calculation of the Alternative 2 Capacity Value consistent with the proposed changes to Alternative 1. In addition, Staff proposed that Alternative 2 be based on performance during the 240 to 245 hours on non-holiday weekdays from June 24 through August 31, during the hours of 1:00 PM through 6:00 PM EDT, rather than the 460 hours previously used. As described above, commenters identified flaws in Staff's methodology, including the assignment of hours. For that reason, while Alternative 2 will be modified to 240 or 245 hours, those hours shall be the hours of 2:00 PM to 7:00 PM on non-holiday weekdays from June 24 to August 31. In addition, rather than using solar PV load curves to determine compensation during those hours, the total $/kW-year value shall simply be divided by 240 or 245, based on the number of available hours that year, such that a project can earn the entire value by generating during each of those hours. That total $/kW-year value shall be determined each year based on the sum of the most recently available monthly NYISO $/kW-month auction prices for the 12 prior months as of May 31 of each year.[15]

[14] As always, this calculation should be "grossed up" for the appropriate avoidable loss percent and excess ICAP purchase percent, as discussed in each utility's mandatory hourly pricing tariff.

[15] As in Alternative 1, this calculation should be "grossed up" for the appropriate avoidable loss percent and excess ICAP purchase percent, as discussed in each utility's mandatory hourly pricing tariff.

PSEG requests that a larger window, starting June 1, be used for certain utilities. While such by-utility modification is appropriate for DRV windows, as discussed above, it is not appropriate for capacity compensation windows. The utilities are billed for capacity based on usage during the single peak statewide hour as determined by the NYISO. This hour does not vary by utility territory or load zone; the same hour is used to determine capacity charges in Long Island, New York City, the Lower Hudson Valley Zone, and the Rest of State Zones. For that reason, the same hours will be used in all utility territories.

Effective Date and Grandfathering

As proposed in the Staff Whitepapers, projects that qualified after July 26, 2018 will receive compensation based on the methodologies established in this Order. Therefore, CDG projects, other than those in Central Hudson and O&R, that qualified[16] after July 26, 2018 will receive the Community Credit rather than an MTC and will receive capacity, DRV, and, if applicable, LSRV compensation based on the methodologies established in this Order. Any CDG project in Central Hudson or O&R that qualified by July 26, 2018 but after its interconnecting utility exhausted MTC Tranche 4, and therefore was not assigned a Tranche position, will also receive compensation based on the methodologies established in this Order. Remote crediting and non-mass-market on-site projects that qualified after July 26, 2018 will also receive capacity, DRV, and, if applicable, LSRV compensation based on the methodologies established in this Order.

[16] As noted above, a project “qualifies” when it meets the standard for placement in a Tranche; that is, when it has a payment made for 25% of its interconnection costs or has its Standard Interconnection Contract executed if no such payment is required.

The Commission recognizes that developers of projects in later stages of development, which qualified before Staff's proposed changes were announced on July 26, 2018, planned those projects, made substantial investments, and entered into contracts in reliance on the compensation methodology in place at the time. In addition, the changes instituted in this Order are designed to work in concert. Because the MTC for each Tranche at each utility was set based on, among other things, expected capacity values using the methodologies established in the VDER Implementation Order, determining Capacity Value based on the newly adopted methodology for a CDG project receiving an MTC could result in that project being overcompensated or undercompensated. For that reason, CDG projects receiving an MTC, that is CDG projects that qualified and were assigned a Tranche position on or before July 26, 2018, will continue to receive compensation based on the original Value Stack as established in the VDER Implementation Order for the 25-year term from their in-service date described in the VDER Transition Order. These projects will not be given the opportunity to opt-in to the new methodologies established in this Order because the Community Credit is differently designed from the MTC such that allowing projects to move from an assigned MTC to a Community Credit could increase net revenue impacts beyond the forecasted level.

With respect to projects that do not receive an MTC, including remote crediting and non-mass-market on-site projects receiving Value Stack compensation, the Commission will similarly offer projects that qualified by July 26, 2018 compensation based on the original Value Stack as established in the VDER Implementation Order for the 25-year term from their in-service date described in the VDER Transition Order. However, because those projects receive only the value-based elements of the Value Stack and because the changes to those elements in this Order are intended to, inter alia, make compensation for those elements more accurate, those projects will be permitted to opt-in to the changes made in this Order. Specifically, a project that would be entitled to grandfathering under the original Value Stack may make a one-time, irreversible decision to receive the new capacity values, DRV, and, if applicable, LSRV by notifying the interconnecting utility. This opt-in must be to the new versions of all applicable values; a project may not choose to receive the modified DRV while still receiving the original capacity values, or vice versa.

CONCLUSION

The changes made in this Order will improve the ability of the Value Stack and related policies to provide appropriate price signals and compensation so that developers and customers design and invest in projects that provide net benefits to the electric distribution grid and will result in appropriate compensation for those benefits. The changes will also increase the transparency, consistency, and accuracy of Value Stack compensation. These changes, and in particular the availability of the Community Credit and other incentives, will provide for more than 1000 MW of additional CDG development, on top of the more than 500 MW of CDG qualified under the Value Stack by July 26, 2018 and the projects in development for remote crediting and on-site generation. This represents a meaningful step towards achievement of the State’s goals for a cleaner, more distributed electric system.

<u>The Commission orders</u>:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, tariff leaves implementing the modifications to the Value of Distributed Energy Resources policy and to the Value Stack in this order, on not less than 20 days' notice to become effective on June 1, 2019.

2. Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies, is initiated. Department of Public Service Staff shall develop and issue a workplan and schedule for such a proceeding.

3. The New York State Energy Research and Development Authority is authorized to spend up to $43,393,813 in previously collected, uncommitted funds collected under the Renewable Portfolio Standard program to provide up-front incentives to projects developed in the Central Hudson Gas & Electric Corporation and Orange and Rockland Utilities, Inc. service territories, as discussed in the body of this Order. Reporting on the use of those funds shall be included in reporting on the NY-Sun program.

4. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1, related to newspaper publication of the tariff amendments described by Ordering Clause 1, are waived.

5. 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 one day prior to the affected deadline.

6. This proceeding is continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

APPENDIX A

DRV and LSRV Compensation

CONSOLIDATED EDISON

DRV = $199.40/kW-yr

4 DRV Areas, based on CSRP windows

For all weekdays except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays:

(A) 11am – 3 pm; June 24 – September 15
(B) 2pm – 6 pm; June 24 – September 15
(C) 4pm – 8 pm; June 24 – September 15
(D) 7pm – 11 pm. June 24 – September 15

(60 weekdays/year x 10 years – 16 weekday holidays) x 4 hours = 2336 hours in the 10-year period.

$199.40/kW-yr x 10 years / 2336 hours (= $0.8536/kWh) for any eligible injection in those hours.

LSRV = $140.76/kW-yr

Uses existing LSRV Areas, and remaining MW caps

LSRV Call Windows (Same as DRV)

Calls will be within the above DRV windows

21-hour advanced notice. Minimum 10 calls per year, guaranteed. Each call will be for a minimum of 1 hour, up to a maximum of 4 hours, within the above windows.

Divide $140.76 by 10 (= $14.0760/kW per call). The minimum hourly net kW injection during the call window shall be used to calculate the kW quantity provided during each call. Thus, if one call is for 3 hours, and a resource injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of the call, the resource will be credited 1.5 x $14.0760 = $21.11 for that call.

Utility may request more than 10 times if needed, but has no obligation to do so, and the resource would receive no penalties for not responding to calls—just no payment for non-responsive calls.

Any project that qualifies prior to the end of the MCOS proceeding gets the DRV and LSRV prices and windows locked-in for 10 years.

Orange and Rockland

DRV = $64.78/kW-Yr

DRV Window

5 hours per weekday except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays

Hour Beginning 2:00 p.m. until, but not including, Hour Beginning at 7:00 p.m.

June 24th - September 15th

(60 weekdays/year x 10 years – 16 weekday holidays) x 5 hours = 2920 hours in the 10-year period.

$64.78/kW-yr x 10 years / 2920 hours (= $0.2218/kWh) for any eligible injection in those hours.

LSRV = $39.61/kW-yr

Uses existing LSRV Areas, and remaining MW caps

21-hour advanced notice. Minimum 10 calls per year, guaranteed. Each call will be for a minimum of 1 hour, up to a maximum of 4 hours.

LSRV Call Window(s):

Default: Calls will be within the above DRV windows;

Alternative: Utility may group LSRV areas into up to 4 LSRV time groups with different 4-hour call windows, based on sub-system load peaks.

Divide $39.61/kW-Yr by 10(= $3.9610/kW per call). The minimum hourly net kW injection during the call window shall be used to calculate the kW quantity provided during each call. Thus, if one call is for 3 hours, and a resource injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of the call, the resource will be credited 1.5 x $3.9160 = $5.87 for that call.

Utility may request more than 10 times if needed, but has no obligation to do so, and the resource would receive no penalties for not responding to these calls-just no payment for non-responsive calls.

Any project that qualifies prior to the end of the MCOS proceeding gets the DRV and LSRV prices and windows locked-in for 10 years.

Central Hudson

DRV = $14.55/kW-Yr

DRV Window

5 hours per weekday except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays

Hour Beginning 2:00 p.m. until, but not including, Hour Beginning 7:00 p.m.

June 24th - September 15th

(60 weekdays/year x 10 years – 16 weekday holidays) x 5 hours = 2920 hours in the 10-year period.

$14.55/kW-yr x 10 years / 2920 hours (= $0.0498/kWh) for any eligible injection in those hours.

LSRV = No Current LSRV

If/when an LSRV is established, the 10-call minimum approach described for the other utilities will be used.

Any project that qualifies prior to the end of the MCOS proceeding gets the DRV and LSRV prices and windows locked-in for 10 years.

National Grid (Niagara Mohawk)

DRV = $61.44/kW-Yr

DRV Window

5 hours per weekday except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays

Hour Beginning 2:00 p.m. until, but not including, Hour Beginning 7:00 p.m.

June 24th - September 15th

(60 weekdays/year x 10 years – 16 weekday holidays) x 5 hours = 2920 hours in the 10-year period.

$61.44/kW-yr x 10 year / 2920 hours (= $0.2104/kWh) for any eligible injection in those hours.

LSRV = $30.72/kW-yr

Uses existing LSRV Areas, and remaining MW caps

21-hour advanced notice. Minimum 10 calls per year, guaranteed. Each call will be for a minimum of 1 hour, up to a maximum of 4 hours.

LSRV Call Window(s):

Default: Calls will be within the above DRV windows;

Alternative: Utility may group LSRV areas into up to 4 LSRV time groups with different 4-hour call windows, based on sub-system load peaks.

Divide $30.72/kW-yr by 10(= $3.0720/kW per call). The minimum hourly net kW injection during the call window shall be used to calculate the kW quantity provided during each call. Thus, if one call is for 3 hours, and a resource injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of the call, the resource will be credited 1.5 x $3.0720 = $4.61 for that call.

Utility may request more than 10 times if needed, but has no obligation to do so, and the resource would receive no penalties for not responding to these calls—just no payment for non-responsive calls.

Any project that qualifies prior to the end of the MCOS case gets the DRV and LSRV prices and windows locked-in for 10 years.

Rochester Gas and Electric

DRV = $31.92/kW-Yr

DRV Window

5 hours per weekday except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays

Hour Beginning 2:00 p.m. until, but not including, Hour Beginning 7:00 p.m.

June 24th - September 15th

(60 weekdays/year x 10 years – 16 weekday holidays) x 5 hours = 2920 hours in the 10-year period.

$31.92/kW-yr x 10 years / 2,920 hours (= $0.1093/kWh) for any eligible injection in those hours.

LSRV = $47.96/kW-yr and $9.47/kW-yr

Uses existing LSRV Areas, and remaining MW caps

21-hour advanced notice. Minimum 10 calls per year, guaranteed. Each call will be for a minimum of 1 hour, up to a maximum of 4 hours.

LSRV Call Window(s):

Default: Calls will be within the above DRV windows;

Alternative: Utility may group LSRV areas into up to 4 LSRV time groups with different 4-hour call windows, based on sub-system load peaks.

Divide $47.96/kW-yr by 10(= $4.7960/kW per call). The minimum hourly net kW injection during the call window shall be used to calculate the kW quantity provided during each call. Thus, if one call is for 3 hours, and a resource injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of the call, the resource will be credited 1.5 x $4.7960 = $7.19 for that call. A similar method shall be used for the $9.47/kW-yr area.

Utility may request more than 10 times, if needed to, but has no obligation to do so, and the resource would receive no penalties for not responding to these calls-just no payment for non-responsive calls.

Any project that qualifies prior to the end of the MCOS proceeding gets the DRV and LSRV prices and windows locked-in for 10 years.

New York State Electric and Gas

DRV = $29.67/kW-Yr

DRV Windows

Summer: 5 hours per weekday except for NERC Holidays (Independence Day, Labor Day) that fall on weekdays
Hour Beginning 2:00 p.m. until, but not including, Hour Beginning 7:00 p.m.; June 24th - September 15th
(60 weekdays/year x 10 years – 16 weekday holidays) x 5 hours = 2920 hours in the 10-year period.
Winter: 2 hours per weekday except for NERC Holidays (New Years Day) that fall on weekdays
Hour beginning 5:00 p.m. until, but not including, Hour Beginning 7:00 p.m.; Month of January
(31 days/year x 10 years – 90 weekend days – 8 weekday holidays) x 2 hours = 424 hours in the 10-year period.

Total Hours = 2920 + 424 = 3344

$29.67/kW-yr x 10 year / 3344 hours (= $0.0887/kWh) for any eligible injection in those hours.

LSRV = $53.59/kW-r and $56.26/kW-yr

Uses existing LSRV Areas, and remaining MW caps

21-hour advanced notice. Minimum 10 calls per year, guaranteed. Each call will be for a minimum of 1 hour, up to a maximum of 4 hours.

LSRV Call Window(s):

Default: Calls will be within the above DRV windows;
Alternative: Utility may group LSRV areas into up to 4 LSRV time groups with different 4-hour call windows, based on sub-system load peaks.

Divide $53.59/kW-yr by 10(= $5.3590/kW per call). The minimum hourly net kW injection during the call window shall be used to calculate the kW quantity provided during each call. Thus, if one call is for 3 hours, and a resource injects 1.5 kW, 3 kW, and 2 kW for each of the three separate hours of the call, the resource will be credited 1.5 x $5.3590 = $8.09 for that call. A similar method shall be used for the $56.26/kW-yr area.

Utility may request more than 10 times if needed, but has no obligation to do so, and the resource would receive no penalties for not responding to these calls—just no payment for non-responsive calls.

Any project that qualifies prior to the end of the MCOS proceeding gets the DRV and LSRV prices and windows locked-in for 10 years.

Community Credit Availability[1]

Tranche	**ConEd**	**Orange & Rockland**	**NYSEG**	**Central Hudson**	**National Grid**	**RG&E**
0/1	7.9 of 135.9 MW CLOSED	20 of 23 MW CLOSED	61 of 62 MW CLOSED	27 of 39 MW CLOSED	86.6 of 140 MW CLOSED	29 of 28 MW CLOSED
2	N/A	10 of 12 MW CLOSED	70 of 84 MW CLOSED	18 of 19 MW CLOSED	N/A	38 of 42 MW CLOSED
3	N/A	32 of 12 MW CLOSED	62 of 77 MW CLOSED	31 of 19 MW CLOSED	N/A	3 of 41 MW CLOSED
4	N/A	15 of 15 MW CLOSED	N/A	21 of 20 MW CLOSED	N/A	N/A
Community Credit	0 of 350 MW	N/A (Incentive available for at least 45 MW)	0 of 125 MW	N/A (Incentive available for at least 50 MW)	0 of 525 MW	0 of 80 MW

[1] All numbers in MW AC. This chart does not include projects that qualified after July 26, 2018; those projects will be placed in the Community Credit Tranche and count towards its limit. The numbers of MW in closed Tranches are an estimate and may vary slightly based on project qualification dates.

SUMMARY OF DRV, MTC, AND COMMUNITY CREDIT APPLICABILITY

Project Type	Compensation Methodology	MTC or Community Credit for Mass Market Customers	Community Credit for Other Customers	DRV Applicability	DRV and Capacity
NEM or Phase One NEM (On-Site, RNM, or CDG)	Net Metering (Projects may opt into Value Stack)	N/A	N/A	N/A	N/A
CDG (Tranche 1, 2, 3, or 4) (Applicable if Qualified by July 26, 2018)	Value Stack	MTC Per Tranche	N/A	Non-Mass Market Customers Only	Original VDER Methodologies
CDG (New Project in National Grid, NYSEG, or RGE) (Applicable if Qualified After July 26, 2018)	Value Stack	Community Credit of $0.0225	$0.0225	All Customers	New Methodologies
CDG (New Project in Con Edison) (Applicable if Qualified After July 26, 2018)	Value Stack	Community Credit of $0.12	$0.12	All Customers	New Methodologies
CDG (New Project in O&R or Central Hudson) (Applicable if Qualified After Tranche 4 Filled)	Value Stack	None	None	All Customers	New Methodologies
On-Site (750 kW or less AC)	Phase One Net Metering (Projects may opt into Value Stack)	N/A	N/A	N/A	N/A
On-Site (>750 kW) or Remote Crediting (Not eligible for NEM or Phase One NEM and Qualified by July 26, 2018)	Value Stack	N/A	N/A	All Customers	Original VDER Methodologies; May Opt in to New Methodologies
On-Site (>750 kW) or Remote Crediting (Qualified After July 26, 2018)	Value Stack	N/A	N/A	All Customers	New Methodologies

SUMMARY OF COMMENTS

Party Commenters

Acadia Center (Acadia)

Acadia Center, Coalition for Community Solar Access, Natural Resources Defense Council, New Yorkers for Clean Power, New York Solar Industries Association, Pace Energy and Climate Center, Solar Energy Industries Association, Vole Solar (Million Solar Strong Campaign) (MSSC)

Advanced Energy Economy Institute, on behalf of Advanced Energy Economy, the Alliance for Clean Energy New York, and the Northeast Clean Energy Council (AEE Institute)

Alliance for a Green Economy (AGREE)

Azure Mountain (AMP)

Binghamton Regional Sustainability Coalition (BRSC)

Bloomberg, L.P. (Bloomberg)

Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, and Rochester Gas and Electric Corporation (Joint Utilities)

Central New York Regional Planning and Development Board (the Board)

CertainSolar (CS)

Clean Energy Parties (Solar Energy Industries Association, Coalition for community Solar Access, Natural Resources Defense Council, New York Solar Energy Industries Association, Pace Energy and Climate Center, and Vote Solar) (CEP)

Citizens for Local Power (CLP)

City of New York (City)

Energy Democracy Alliance (EDA)

GreenSpark Solar (GSS)

Long Island Solar Energy Industry Association (LISEIA)

Multiple Intervenors (MI)

New York Battery and Energy Storage Technology Consortium, Inc. (NY-BEST)

New York Power Authority (NYPA)

New York State Office of General Services (OGS)

Nucor Steel Auburn, Inc. (Nucor)

Peak Power Energy (Peak Power)

PSEG Long Island (PSEG)

Solstice Initiative, Inc. (Solstice)

Sullivan Alliance for Sustainable Development (Sullivan Alliance)

SunCommon

Public Commenters

Assemblyman Steven Englebright, NYS Assembly, 4th District

Senator Todd Kamisky, NYS Senate, 9th District

Assemblyman Bill Magnarelli, NYS Assembly, 129th District

Senator Jen Metzger, NYS Senate, 42nd District

Assemblyman Phil Steck, NYS Assembly, 110th District

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I. Whitepaper Regarding Future Value Stack Compensation

A. Community Credit

Acadia argues that the Community Credit has the potential to increase the proliferation of CDG projects. The Community Credit can be lower than the existing MTC and still ensure that projects are developed. Acadia believes that Staff should carefully monitor the tranches to ensure that these projects are moving forward and consider adjusting the Community Credit upward if these anticipated projects do not materialize.

AGREE supports Staff's proposal to phase out the MTC in some upstate territories in favor of a new Community Credit that can be layered with the DRV available to all customer of CDG projects. This will help enable the inclusion of "anchor customers" in CDG projects. AGREE believes that the Community Credit plus DRV combination still adds up to a value that is inadequate to meet the goal of robust CDG development in all parts of the state. AGREE believes that the Community Credit should be increased to at least 3.25 cents. This value, if layered with the DRV, will enable those projects to move forward. However, the DRV is less predictable than the Community Credit, as its value can change every two years, while the Community Credit has a value that is locked in for life.

AGREE states that for residential customers in National Grid, RG&E, and NYSEG territories, the proposal reduces the value of the predictable Community Credit and exchanges that for a less predictable DRV value. This added unpredictability for residential customers will make it harder for residential customers to understand the value they will receive from their portion of the generation of the CDG project. AGREE strongly encourages the Commission to create a higher floor value for the DRV or to fix the value of the DRV for life with an escalator.

AGREE notes that Staff's proposal does not address residential master metered buildings access to CDG. These buildings and their residents are not eligible for the MTC, which means they would receive a much lower value for any generation from a CDG project. This could be remedied by extending the MTC to residential master metered buildings so that the MTC covers all accounts serving residential customers in New York, without discrimination. Alternatively, the Commission could make a Community Credit available to master metered customers like that being made available in some upstate utility territories, but adjusted so the value matches the MTC in Con Edison territory minus the DRV.

AMP supports the Community Credit although its value in National Grid’s territory is too low and demonstrates a technology bias in favor of solar. AMP argues that small hydro will have a lower DRV value than solar, as hydro is at its lowest production in the summer months while solar is at its highest.

Bloomberg supports Staff's recommendation to create a Community Credit, and recommends that Staff immediately calculate the Community Credit for Con Edison and give CDG projects the option to elect either the MTC model or the Community Credit model. Bloomberg states that the existing Value Stack framework does not provide enough incentive for large corporate entities to participate in New York City CDG projects as anchor customers. For example, large customers currently are not eligible to receive the MTC, which comprises as much as half of the total Value Stack compensation that a smaller customer might receive. Bloomberg notes that only 16.6 MW (out of 136 MW) of Value Stack Tranche 1 compensation available for CDG projects in Con Edison's service territory has been allocated. In comparison, each of the other utilities have nearly fully-subscribed all of their respective Value Stack Tranches.

Bloomberg believes that increased interest from anchor customers would help reduce the overall financing and customer acquisition costs of CDG projects. Also, it would be easier for developers to attract smaller (i.e., mass market) customers to the project. Large anchor customers also could market the 60% portion of each CDG project that is allocated to mass market customers to their employees and stakeholders, thereby increasing awareness of, and interest in, CDG participation.

Bloomberg further recommends that the Commission should provide developers in the Con Edison territory with the option to either be allocated capacity under Tranche 1 (at Staff's proposed higher MTC value of $0.1435/MWh), or avail themselves of the new Community Credit model. According to Bloomberg, this would provide developers more flexibility to find participants for the CDG projects, for example, by attracting more mass market customers through greater MTC compensation. Second, it would immediately open up the large anchor customer market in New York City, without first having to wait for the remaining 120 MW of Tranche 1 capacity to first be filled.

CEP supports Staff’s proposal to offer a community credit, and supports the inclusion of the 1 cent/kWh anchor-tenant credit as a measure to encourage more mature CDG projects that already have tranche allocations to seek anchor tenants. CEP argues that the Community Credit is a substantial improvement over the MTC construct. CEP believes that the widespread demand for non-residential CDG projects is evident by the thirty-four community and environmental justice groups that called for an expansion of the MTC to all customers. CEP states that the lack of anchor tenants caused by the inability of demand rate customers to effectively participate in CDG thereby has the unnecessary effect of raising soft costs for CDG projects, and the Community Credit rectifies this problem.

However, CEP notes that project costs may increase due to a number of factors beyond a solar firm's control and thereby may require an increase in the Community Credit at some future point. CEP argues that the projects allocated in the pre-July 2018 MTC tranche allocations should be allowed to participate in the Community Credit. Also, those making 25% interconnection payments before July 26 should be allowed the option of simply opting into the entire new Community Credit approach while retaining their current tranche allocation. CEP recommends that staff periodically review the usage of the MTC, including attrition of projects that previously secured an MTC and the conversion of projects from MTC to Community Credit, and consider adding additional capacity in the Community Credit tranches to reflect the lower-than-expected rate impact of the original MTC.

CEP requests a clarification that projects that receive a Community Credit be able to bank the full value of any unallocated credits (including the Community Credit and Anchor Credit).

In their reply comments, CEP claims that the Joint Utilities argument that the Community Credit is unnecessary to support distributed solar projects is flawed. First, CEP believes that NYSERDA's modeling and the generally weak state of the market demonstrate that the Community Credit is justified and needed to spur further distributed solar deployment towards the 6 GW target by 2025. CEP disagrees with the Joint Utilities comments that the community credit is "unnecessary" because it presumes that the inclusion of non-residential customers is not an objective of the CDG program established by the Department in 2015. CEP sees that the current barrier to the participation of non-residential customers is a result of the challenges of the first iteration of the VDER tariff, and the Community Credit approach is an important interim measure to ensure non-residential participation in CDG projects.

CEP argues that the Joint Utilities' assertion that the Community Credit will result in a less cost-effective outcome than if customers installed renewable energy facilities on-site is unsubstantiated and misplaced. The Joint Utilities have argued that onsite solar projects would be more cost-effective than off site projects. However, CEP notes that they have made no demonstrations that that is true. CEP states that while the

Joint Utilities comments claim that on-site projects would be more efficient because they would reduce line losses and be sited close to load, these comments fail to consider the possibility that the development of other distribution-connected CDG projects on circuits that also serve load will also reduce line losses.

CS supports the Community Credit but recommends including Con Edison in the policy.

GSS supports the Community Credit, although it is not adequate for residential customers. The credit is below retail and is a significant barrier to selling shares in community solar projects. GSS argues that the proposal ignores the difficulties facing commercial and industrial customers, especially those projects without residential offtakers. GSS notes that the compensation levels that were proposed in the original Value Stack have remined 10-20% lower than NEM.

Joint Utilities argue that the addition of a Community Credit creates an unnecessary increase in costs for all customers without providing incremental benefits. The Joint Utilities note that recipients of the Community Credit would also be eligible to receive DRV compensation. Therefore, the Joint Utilities state that there is no need for the Community Credit and it should be rejected. The Joint Utilities agree that the presence of an anchor customer provides financial benefits to CDG projects, but believe these benefits are already sufficient without any additional compensation. The Community Credit proposal will likely increase customer costs because all CDG subscribers will receive the credit and be eligible for the DRV. Offering the DRV and the Community Credit to all CDG subscribers will allow commercial and industrial subscribers to receive a higher credit than most upstate mass-market customers receive under the MTC in Tranches 3 and 4.

The creation of volumetric credits is especially problematic for higher capacity factor NEM technologies, such as fuel cells and wind, which could receive a disproportionately high subsidy, according to the Joint Utilities. Another flaw is that the Community Credit proposal will result in greater compensation to demand-billed customers who subscribe to CDG than they would receive if they installed their own on-site systems. The Joint Utilities argue that the proposal to retroactively extend a Community Credit of $0.01/kWh to non-mass market participants in Tranches 1, 2, 3, and 4 would provide unnecessary additional subsidies to developers of existing, financed, and operational CDG projects.

MI states that it does not typically support non-cost-based subsidies, such as the MTC or the proposed Community Credit. The whitepaper does not specify how the proposed Community Credit ultimately would be funded, other than via a reduction to the MTC. If the costs of the proposed Community Credit are not allocated to large non-residential service classes, then MI advocates no formal position. If the costs of the proposed Community Credit would be allocated to large non-residential service classes, then MI opposes Staff proposal and urges the Commission to reject it. MI supports cost-based rates, reflecting the actual costs to serve customers, thereby promoting equity, fairness, and the provision of accurate price signals.

Nucor states that the proposal to re-brand the MTC as a Community Credit is ill-advised, distorts the purpose in establishing an MTC in the first place, and should not be adopted. Nucor supports adherence to both the 2% net revenue impact cap, as well as the hard MW cap that has been established to limit the impacts of MTC compensation to non-participants. If the revamped credit is adopted, Nucor recommends that the extra-market credit continue to be termed an MTC, that the prevailing hard MW caps for all Tranches be respected, and that the Commission emphasize a clear-cut phase-in toward full value stack compensation.

SunCommon supports Staff’s recommendations regarding the treatment of post-Tranche 4 projects in O&R and Central Hudson. There is a very limited number of projects, however, which have already expended substantial resources and were moving toward utility interconnection agreements when Tranche 4 was exhausted. These projects should be given the option of receiving the additional up-front incentive or the 3 cent MTC suggested in the whitepaper. This transitional arrangement should apply only to projects which had meaningfully advanced with local permitting and for which the utilities had accepted complete applications as of the date Tranche 4 was exhausted. The impact to ratepayers or the utilities of doing so would be minimal and will in all likelihood be offset by Tranche 1 to 4 projects which will not be able to secure local permitting and therefore not be built.

The Board argues that the creation of the Community Credit does not provide enough improvement to make the SolarizeCNY portfolio in their region viable. Further, the Board recommends an increase in the Community Credit in National Grid and NYSEG’s territories to at least 3.25 cents/kWh and a similar increase in the RG&E territory. The Board argues that this increase, if layered with the DRV, will enable SolarizeCNY to move forward.

The City recommends a Community Credit for Con Edison immediately, and allowing developers to opt-in to the Community Credit. The City sees no reason why the Community Credit should not be immediately available to developers siting CDG projects in Con Edison's territory, or why Staff should delay calculating a Community Credit value for the service territory. It is unclear whether increasing the current Tranche 1 MTC value will be enough to overcome those barriers and encourage developers to fill up Tranche 1; if not, then issues plaguing the MTC framework (e.g., master-metered customers cannot access it, and therefore receive less benefits from participating in a CDG project) will continue to exist.

The City believes that by acting now to establish the Community Credit, the Commission will avoid a potential cliff date that will arise in Con Edison's territory once the Tranche 1 allocation is fully subscribed. The City recommends that the Commission establish a mechanism for new CDG developers to opt-in to the Community Credit framework rather than taking MTC compensation, and direct Staff to establish a fully-transparent process to calculate the Community Credit value, as well as the number of MWs available under the Community Credit framework. If the Commission declines to allow developers to opt-in then the MTC should be immediately expanded to include master-metered buildings, in order to remedy the ongoing discriminatory treatment of sub-metered customers. The City requests clarification that the Community Credit will be available to customers living in master-metered/sub-metered buildings.

According to the City the Commission should clarify that, for Community Credit purposes, master-metered residential buildings will continue to not be subject to the currently-existing requirement that only 40% of a CDG project's output be dedicated to large customers over 25 kW. The 40% cap would effectively limit the number of master-metered customers that can participate in a CDG project and receive a Community Credit and cause the same issues that arose when residents of such buildings were unable to access the MTC. Instead, the Commission should continue the practice of allowing a master-metered building to report the number of small occupants sized at less than 25 kW, who would be treated as individual CDG project members not be subject to the 40% cap.

The City states that the Commission should direct Con Edison to develop rules that enable NYPA customers to participate in CDG projects. The City has indicated on several prior occasions that it could help accelerate the development of CDG projects in New York City by taking on the "anchor" off-taker role. However, as a full requirement supply customer under contract with NYPA in Con Edison's service territory, the City currently is unable to take on such a role in CDG projects with host meters associated with Con Edison accounts. While informal collaboration on this issue with NYPA and Con Edison has been fruitful, the City submits that active Commission direction is needed to resolve the outstanding NYPA participation issue. The City therefore respectfully urges the Commission to direct Con Edison and NYPA to develop the necessary tariff, billing and other changes needed to facilitate participation by NYPA customers (such as the City) in CDG projects.

The City states that the Commission should consider enhancements to the Value Stack framework to promote DER development in underserved communities. It is important for the Commission to incentivize DER development in locations that serve public policy objectives, such as improved system resilience, or increased clean energy opportunities for communities that traditionally have borne a disproportionate burden of prolonged under-investment, pollution, and corresponding public health and socio-economic impacts. To that end, the City supports the development of new components to the Value Stack, such as an environmental justice adder.

B. DRV Value

AEE Institute recommends that the Commission adopt the same hours for DRV and ICAP Option 2. Solar only resources would have a DRV window of 2-7 pm and hybrid solar + storage resources would have a DRV window of 3-7 pm. A MW of storage output from 6-7 pm will be far more valuable to the future system than a MW from 2-3 pm, when solar is near its peak output. The windows should align with this reality.

AEE Institute supports Staff’s proposal to allow projects that prefer a smaller number of hours with a call signal to opt out of receiving the DRV and instead participate in the utility CSRP. Staff appropriately recognizes that not every project will want to operate for the entire 245 hour period in the summer, and that a project’s availability during the highest of the peak load hours, as represented by the CSRP dispatch trigger, can provide high system value. With that said, some features of current CSRPs are likely to pose barriers to some types of DER that are currently eligible to participate in VDER. We therefore support Staff’s recommendation to direct utilities to modify the rules of their CSRPs to permit resources to perform by injecting electricity into the distribution system.

AEE Institute also recommends that the Commission direct utilities to modify the rules of their DLRP to permit resources to perform by injecting electricity into the distribution system. Allowing injections during DLRP events, which are triggered by local contingencies, could strengthen reliability.

The current DRV construct compensates for injections during the 10 highest load hours, even if those injections are persistent for all of the other hours of the day and year. Switching from the current DRV construct to the CSRP would result in a loss of compensation for certain types of generators, such as fuel cells. The generation profile of these baseload DERs should be delineated from the load profile of customers so that appropriate compensation is provided. The same is true for energy storage resources; performance for the storage should be measured at the battery level and be evaluated exclusively on the performance of the battery during the DRV or capacity interval on that specific day.

The CSRP value should equal the proposed DRV value, unless there is adequate rationale for why the CSRP and DRV values should be different. If a project is available and performs during the CSRP dispatch trigger, which for most utilities is 92% of the system peak or network peak, it would seem to avoid similar costs as represented by DRV. A resource that performs during the top 245 peak hours of the year may have more value than a resource that performs for fewer hours. However, even under Con Edison’s current VDER tariff, the compensation is $199.40/kW-yr for a resource available for the top 10 peak hours, although CSRP compensation is currently $90/kW-yr, even though the program is dispatched at 92% of utility or network peak. For many utility territories, this means that CSRP is dispatched in excess of ten hours a year. Therefore, we contend that the CSRP value should equal at least this $199.40/kW-yr (or the DRV value in other territories), unless utilities can provide adequate rationale for the CSRP being lower.

Finally, it is critical that projects that participate through VDER have the option of receiving the DRV value through payments instead of bill credits, recognizing that customers with higher bills will still prefer bill credits. For standalone projects that do not have associated accounts for which the bill credits could be transferred, or that have accounts with minimal charges, not receiving payment serves as a major impediment to developing a project and accomplishing state storage goals. Developers for such projects need to find third party off takers who can utilize the bill credits, adding a complicated layer to developing a project.

In reply comments, AEE Institute opposes the Joint Utilities proposal to de-rate the DRV by an assumed solar coincidence factor that attempts to cap DRV compensation by the amount of capacity of a modeled system would provide during the top 10 peak demand hours on a utility distribution system. AEE Institute sees this proposal as unworkable because modeled output for stand-alone solar facilities is inexact. AEE

Institute suggests that Capacity Option 2 is available for non-dispatchable technologies.

AEE Institute is concerned about the CSRP's inability to distinguish between baseload distributed generation and baseline consumption, noting that the Joint Utilities pointed out the issues with the inability of some technologies to participate in the CSRP. AEE recommends that the Staff thoroughly analyze the differences between the DRV and CSRP programs and resolve any disparities prior to eliminating the 10-hour measurement period for the DRV compensation for dispatchable resources.

AMP supports the proposed structure of the DRV, but believes the total value is still too low and biased towards solar. AMP believes the proposal of substituting specific peak 240 or 245 hours for the measured 10 peak load hours will provide more reliable compensation while still rewarding generators that make meaningful contributions to system peaks.

CEP supports the use of marginal costs for the utilities' EE benefit-cost calculations for the DRV, as these values have been vetted and approved by the Commission and because no better proxy exists for the avoided distribution cost value that DER can provide. CEP states that the move to include more than the top 10 hours in the performance period is fully justified. CEP states that because of the probabilistic nature of distribution peaks, loadings on distribution system equipment can exceed that equipment's design rating for short periods of time; what matters for many types of equipment and many kinds of wear and tear is not so much the single peak hour (or top ten hours), but rather how long that equipment is overloaded. Therefore, CEP states it is much more accurate to send resources a price signal to reduce equipment loadings for more than 10 hours per year, and CEP is supportive of Staff's proposal to use the peak summer hours (excluding weekends and holidays).

CEP recommends slightly changing the dates and hours over which compensation would apply. CEP believes that the data supports a June 1 – August 31 timeframe and a 2 pm – 7 pm window. CEP claims that the proposed dates over which DRV performance would be measured appear overly restrictive and the dates should be extended to June 1, and possibly also into September. To encourage some systems to continue to reduce early afternoon peaks, CEP recommends that Staff also create a 1 pm – 6 pm peak window option for systems to opt into. CEP requests that systems that have already submitted their 25% interconnection payments be allowed to opt into the June 1 – August 31, 2 pm – 7pm peak period proposed in the July Staff whitepaper, as these systems may have been designed to maximize production during the later hours based.

CEP recommends clarifying that the DRV value will be part of the Value Stack bill credits transferred to customers. In addition, CEP recommends that host accounts allocate DRV credits to benefiting accounts evenly over the course of the year, even if these credits are accrued during the summer peak hours. CEP recommends the Commission clarify that this credit smoothing mechanism will remain in place in concert with any updates to the DRV calculation methodology that are adopted.

CEP supports the forward-looking call signal approach as an improved delivery mechanism that more accurately reflects the unique demand-reduction benefits that dispatchable DERs can provide. CEP supports the alignment of the compensation period with the time period over which DERs will be providing distribution services to the grid; i.e., 25 years because this change is necessary to meet VDER's goal of compensating distributed resources for performance in line with distribution system needs.

CEP's concern with Staff's approach on the 5% collar is that it could cause compensation to deviate substantially from the actual value provided by resources. CEP is concerned that if the DRV were to increase substantially due to new forecasted load growth (such as from growth in electric vehicles, heat pumps, or even from an increase in extreme weather events), the compensation would be limited to only 5% above the previous year's value. Further, CEP states that this could lead to significant divergence between the actual avoided cost and the DRV compensation, resulting in less deployment of cost effective DERs and therefore greater need for distribution utility investment. For this reason, CEP proposes that there should be an opportunity for stakeholders to request a reset of the DRV if the results of the MCOS studies reveal that the true value should be significantly higher.

In its reply comments, CEP concurs with the JU and many other commenters that the Value Stack Whitepaper's proposed 240-hour window should be shifted later in the day to the hours of 2pm to 7pm. CEP strongly opposes the Joint Utilities proposal to use an "adjustment factor" to reduce the DRV credit to reflect solar generation during the utilities' top ten hours. CEP reiterates its position that it is not just the top ten hours that drive investments in the distribution system – it is hundreds of hours. CEP believes that DER performance should not be incentivized for only 0.1 percent of the hours of the year but instead should be incentivized to reduce distribution system loads during a larger number of peak hours to reduce the number of hours that equipment may be overloaded.

In addition, CEP believes that the lack of visibility or notification as the hours is unnecessary and unacceptable and cannot be a part of any approach. CEP states that the JU argues that using the avoided cost values that have been approved for use in the energy efficiency proceedings is inappropriate, as the utilities have since filed updated avoided distribution cost (marginal cost) studies. However, CEP believes that these new studies have not been thoroughly vetted or approved by the Commission nor have they been subject to rigorous stakeholder review and examination. In addition, CEP continues to have many concerns and questions regarding the utilities' methodologies. CEP urges the Commission not to approve these values until the methodologies and assumptions that inform them are thoroughly examined through a proceeding designed to investigate these issues. CEP supports the adoption of the five percent collar because of the relative certainty the cap would provide and opposes the Joint Utilities proposal to increase the size of the collar beyond five percent because it would severely compromise the financeability of the DRV component.

Joint Utilities believe that the whitepaper goes against the Commission's objectives to move toward more granular compensation mechanisms for DER, and provides little justification for these proposals beyond providing "predictable compensation" for DER developers. The recommended changes to the DRV structure will increase customer costs beyond the above-market compensation already embedded in the current DRV structure, while removing the LSRV's price signals to encourage developers to locate Value Stack-eligible resources in high-value areas of the distribution system or to adopt project designs and technologies that provide real distribution system benefits. Further, the Joint Utilities state that these changes are expected to result in an estimated $11 million in additional above-market payments to DER statewide in 2021 alone.

The Joint Utilities state that the Commission should continue to compensate DER based-on exports that coincide with actual distribution system peaks. The Joint Utilities claim that for many utilities, a significant portion of their distribution system peaks will occur outside of the paper's 240-hour window. Plus, the use of the broad summer peak window fails to send a sufficiently granular price signals to resources that can reduce distribution system peak load and system costs. The Joint Utilities recommend either continuing to use a compensation methodology that values DER production coincident with the utility's top ten distribution peak hours, or adjusting the DRV to more closely align compensation with value by reflecting the actual DER coincidence with the utility's top ten annual peak hours averaged over five years. Specifically, the Joint Utilities propose the use of a factor to adjust the DRV every two years.

The Joint Utilities support the recommendation that dispatchable resources be eligible to opt out of the DRV and participate in the CSRP, which would help address system needs on both a locational and temporal basis. The Joint Utilities suggest that the Commission establish rules to prevent DER developers from frequently switching between the two options.

The Joint Utilities believe the Commission should set the DRV Compensation rate based on up-to-date cost studies because the studies were developed between 2012 and 2015. However, the Joint Utilities point out that the Commission in its VDER Phase One Order found those same numbers to be inadequate. The Joint Utilities have developed new avoided distribution cost studies with estimates of avoided distribution costs that are directly applicable to the LSRV and/or DRV compensation construct and fully consistent with the Commission's directives above. This information demonstrates that using outdated cost studies and proxy values to establish DRV compensation, contrary to the Commission's express direction, will cause utility customers to pay DER significantly in excess of the actual value provided.

The Joint Utilities argue that the opt-in provision proposed in the Whitepaper, which will likely be exercised by most developers, increases cash flows to developers that have already successfully obtained financing. Therefore, this opt-in recommendation will fail to generate any incremental clean energy or avoid any additional distribution investments and should be rejected.

In reply comments, the Joint Utilities note that other parties express similar concerns regarding the Whitepaper's selection of a fixed set of hours to derive DRV compensation that may not match distribution system peaks. The distribution peaks can be markedly different from statewide peaks, but generally agree with CEP's findings that a static set of hours for all utilities is not optimal. The Joint Utilities suggest that rather than exposing customers to long-term commitments that provide limited customer benefits, DRV compensation should be tied to DER production during each utility's service territory-specific peak hours. Further, to the extent the current 10 peak-hour window creates more volatility than is deemed necessary to support development of eligible resources, a modest expansion to 50 hours may be appropriate.

The Joint Utilities note that the AEE Institute's suggestion that resources could select the peak period for permitting would further separate compensation for resources from the value they provide to the distribution system. Further, The Joint Utilities argue that collars can distort price signals resulting in either over- or under-compensation, and restricting collar adjustments to small amounts exposes customers to the unnecessary risk of paying for value that resources do not provide or, in the alternative, provides DER compensation that is lower than the value provided. The Joint Utilities disagree with the CEP proposal to restrict adjustments to the DRV to those that benefit DER, i.e., by allowing only upward adjustments of the DRV to exceed five percent.

The Joint Utilities state that the AEE Institute recommends that the Commission revise the DRV to make it a payment to customers rather than a bill credit; however, the community solar construct was designed to provide residential customers access to solar power and its benefits, not to provide a revenue mechanism for DER developers, and it would be a gross distortion to transition it into an outright payment rather than a bill credit. NY-BEST recommends that the Commission direct the Joint Utilities to separately meter battery generation for CSRP compensation for both self-consumption and exports. While the Joint Utilities agree that there is value to separately metering the battery, providing CSRP compensation for self-consumption would result in overcompensation due to double-counting, as normal self-consumption already provides the customer with a distribution benefit by avoiding demand charges.

NY-BEST objects to Staff's proposed changes in the calculation methodology for DRV. NY-BEST's concern is that these hours do not properly reflect the existing or trending load shapes and system peaks. By moving the calculation window to align with solar peaks, it discourages solar + storage systems and incentivizes less flexible systems. NY-BEST recommends that the DRV methodology calculation window remain at 2:00 PM- 7:00 PM and that the Commission adopt an additional option for flexible dispatchable projects using a calculation window of 3:00 PM - 7:00 PM.

NY-BEST also recommends that projects be able to lock in their DRV value for the life of the project, but that DRV be reviewed every 2 years and reset accordingly for new projects. This would provide revenue certainty for projects while incorporating a path for the future that reflects changing load shapes for new DER projects going forward.

The Staff Whitepaper recognizes that the timeframe window of 1:00 PM-6:00 PM undervalues dispatchable resources, and suggests that to address this shortcoming, dispatchable resources could opt out of DRV and participate in CSRP and DR programs. NY-BEST does not consider this an option in its current form. NY-BEST agrees that changes will be necessary to utility CSRP programs for this option to be a viable solution. NY-BEST recommends that CSRP/DR programs be revised to ensure that projects are appropriately compensated for their performance in areas/times of need. More specifically, the Commission should direct the utilities to revise the metering &

verification for storage projects under CSRP to exclusively meter the output of the storage during dispatches, and base compensation off that output. Projects must be compensated for the full value of their energy in a DR program, as well as reservation and performance.

NY-BEST also recommends that the Commission direct utilities to revise their DLRP tariffs to allow for injections from behind the meter or front of the meter projects. DLRP is a contingency-based program, and resources that are participating in VDER can strengthen reliability if they can participate in DLRP.

Peak Power supports the addition of a DRV Alternative 2 methodology to provide greater certainty to those who seek it. However, Peak Power believes that this methodology suffers from similar issues as Capacity Alternative 2 and does not properly incentivize or reward technologies that are able to accurately target the top distribution peaks. Also, Peak Power is concerned with limiting the compensation of energy storage and solar + storage projects.

Peak Power does not agree that the utility’s CSRP represents an adequate replacement for the DRV due to the difference in total compensation between these programs. For example, a 1MW/2MWh battery under the current system would be compensated up to $126/kW-year last year. Under the CSRP, this same system would be capable of earning just $30/kW-year under the Con Edison CSRP program. Peak Power supports the comments submitted by NY-BEST recommending CSRP/DR programs be revised to ensure that projects are appropriately compensated for their performance in areas/times of need, for the full value of its energy in a DR program, for reservation and performance. Also, Peak Power agrees with the comments submitted by NY-BEST, that Staff should incorporate utility DLRPs as an option for DERs in lieu of DRV, and that utilities be required to modify DLRP rules to permit resources to inject electricity into the distribution system. Peak Power believes an alternative should be considered to allow BTM DERs to participate in the CSRP program. Also, they should be compensated through the DRV mechanism for their net injections.

Peak Power would like the Commission to consider the opt-in and opt-out process for DRV versus CSRP. Given the complex nature of these compensation mechanisms, Peak Power would like to see DERs given the ability to elect between them by the beginning of each calendar year. Lastly, Peak Power is concerned about Staff’s proposal of retention of 10-hour DRV for CDG customers only. Peak Power strongly advocates that any project be able to opt-in to the 10-hour methodology.

PSEG maintains (i) that the entire month of June should be included and (ii) that the current hours of 2:00 PM to 7:00 PM should also remain. The result is a total of 320 hours for 2019 (64 days, 5 hours per day). As previously explained, there is a greater possibility of a Long Island system peak occurring after 6:00 PM as a result of both higher residential population density and higher humidity levels on Long Island compared to other regions in the state.

The Board recommends creating a floor value for the DRV, or freeze its value with a built-in escalator, which would address the unpredictability of the DRV, which adds confusion for customer subscribers and makes it unnecessarily difficult for developers to secure project financing.

C. LSRV

AEE Institute shares the concerns of NY BEST and CEP that NWAs, as currently implemented, will not provide a sufficient alternative to the LSRV. NWAs could provide a better alternative to the LSRV, but they recommend that the Commission revise the NWA programs to conform with NY-BEST's recommendations prior to eliminating the LSRV.

CEP supports Staff's proposal but notes that it creates increased pressure to ensure that the NWA process is effective. CEP claims that there is relatively little transparency regarding NWA solicitations and the process for identifying NWAs, nor have the utilities provided transparent feedback to contractors who were not selected, which makes it difficult for DER providers to understand how to design solutions that are competitive with the utilities' traditional infrastructure. CEP argues that when annual capital investment plans and biannual DSIPs are filed, there is no formal link between these documents, nor any formal opportunity for stakeholders to review the capital investment plans and help to identify areas where DERs can avoid investments. CEP recommends that a Distribution Planning Advisory Group be established in New York.

In its reply comments, CEP opposes the Joint Utilities proposal to sunset the LSRV, claiming that it will remove the price signals that encourage developers to locate resources in high-value areas of the distribution system. However, CEP does acknowledge that the NWS process should be improved since we are not seeing the number of successful NWS as expected. CEP recommends reviewing the existing challenges with how the NWS opportunities are created, contracted and structured. CEP agrees with the challenges noted by NY-BEST, including that contract term lengths are often too short and should be at least seven years. The Joint Utilities argue that the DRV must exclude high-value, locational needs. While CEP agrees that locations that have contracted non-wires alternatives should be excluded, it is inappropriate to exclude locations without non-wires alternatives from the calculation of the DRV once the LSRV is no longer offered. CEP argues that not all developers are able to participate in non-wires solicitations or DR. programs, yet they can still provide value to the system. Therefore, CEP argues that these projects should be compensated based on the DRV, which includes both low-value and high-value areas without non-wires solicitations.

CS urges the Commission to preserve the LSRV value stack component because the elimination will significantly impact the economics of the CDG projects and impact the market for CDG subscriptions. If the LSRV should sunset, CS requests a transition period of 48 months.

Joint Utilities argue that the Commission should retain locational price signals to encourage DER where most beneficial to the system and all customers. The proposal to eliminate the LSRV and revise the DRV combine to work against the Commission's stated objectives of moving toward more granular, value-based compensation mechanisms that encourage the deployment of DER in high value areas and their operation during actual distribution system peaks discussed above. Without a properly developed and dynamic LSRV mechanism, the Joint Utilities believe the revised DRV will effectively nullify locational price signals for DER, particularly for solar generation. Further, in order to avoid this unintended outcome, the DRV must exclude the cost of high-value, locational needs; Instead, there must be a properly developed and biennially updated LSRV.

In reply comments, the Joint Utilities note that the Whitepaper's proposal to eliminate the LSRV is inconsistent with the Staff's MDI Working Group charge, and until that work is completed the LSRV should be retained to maintain the link between the value of DER and the compensation paid for that value. The Joint Utilities agree with NY-BEST that NWAs are unlikely to fully meet the need for locational price signals if DER developers have the option of instead receiving payments through a 25-year tariff mechanism that provides for above-market compensation with minimal performance requirements.

NYPA believes that the retroactive phase out of the LSRV may create a precedence of regulatory uncertainty and impact future DER development, and that the LSRV should be extended for the projects qualifying prior to 30 days after the Commission Order. NYPA points out that many of these projects have made or plan to make the financial commitment of 35% of the projects interconnection costs prior to the issuance of the Order. NYPA argues that a decision to back date the effectiveness of such a change would create distrust in the regulatory regime and adversely affect future DER deployment. NYPA states that the new DRV compensation method and phasing out of LSRV should be no earlier than the date of the marginal cost of service studies scheduled in 2020.

NYPA argues that timely utility decision on NWS solicitation can serve as the price signal to induce DER development where the system needs it the most. Further, NYPA believes that the lack of clarity and timeliness in the utility NWS process has impacted the DER project developers' ability to secure project financing, determine project economics and decide on whether or not to proceed. NYPA suggests the Commission should direct the utilities to allow more transparency and clarity in the utility NWS process, and establish a timeframe for project selection and incentive calculation. Further, utilities should have a reporting requirement to assure strict compliance with any prescribed decision making process and timeline.

NY-BEST agrees with Staff that the current LSRV compensation mechanism is imperfect, although it is concerned about eliminating it in its entirety and relying on the equally imperfect DSIP process, NWAs, and Demand Response programs to fill this need. NY-BEST believes that this proposal will not help build a robust DER market and it will not maximize the system benefits of DERs. NWA procurements are sporadic and, to date, have resulted in awards to only a limited number of selected vendors. NY-BEST believes that before the Commission proceeds with sunsetting LSRV, it must first adopt revisions to the DSIP, NWA and DR programs to increase transparency, remove unnecessary barriers to participation (i.e., project size, ability to aggregate projects), and properly value and compensate DER benefits (i.e., change base-line measurements in DR programs).

Peak Power believes that the current LSRV mechanism is imperfect, but Peak Power does not see how transitioning to the equally imperfect DSIP process resolves the current issues.

D. Market Transition Credit

CS supports the proposal to increase the MTC, and argues that an innovative mechanism to reach low-income customers could be to modify the rules for banked VDER credits. CS suggests that the VDER tariff should be modified to allow credits to maintain full MTC value if the off-taker is an LMI customers. CS states that this policy makes LMI customers a perceived asset to CDG financiers rather than a liability. CS recommends expanding the MTC eligibility to master-metered apartments.

Joint Utilities state that a four cent/kwh increase to Con Edison's MTC is an unnecessary increase in costs for all customers that will not provide net benefits. The proposed increase would raise CDG compensation to levels 20 percent higher than the current incentive offered under NEM to mass-market customers installing their own roof-top solar systems. The Joint Utilities note that this change would bring the effective premium of providing renewable power from CDG projects in the Con Edison service territory to more than $0.18/kwh, or ten times NYSERDA's average cost to procure large-scale renewable generation in its most recent solicitation. The Joint Utilities suggest that instead of artificially inflating the Con Edison MTC, it would be more cost effective for Con Edison to develop a green tariff to provide renewable power to interested customers from new utility-scale generators.

In reply comments, the Joint Utilities note that MI and Nucor agree with the Joint Utilities that additional bill impacts on customers should be limited and that subsidies not linked to specific value contributions are inappropriate. The Joint Utilities note that the MTC already includes the distribution value, and therefore allowing subscribers to receive both a Community Credit and the DRV will not reduce impacts on customers but actually increase costs to customers.

The Joint Utilities disagree with the City's proposal for a higher MTC for Con Edison because it is not necessary, and note that as of March 1, 2019, Con Edison's interconnection queue contains an additional 84.7 MW of eligible projects including 42.5 MW of fuel cell projects. The Joint Utilities oppose revisiting the policy of extending MTC to master-metered buildings mentioned by several stakeholders, and urges the Commission to reject it because there is no compelling evidence to support it. The Joint Utilities reiterate their opposition to the creation of the Community Credit described in the Value Stack Whitepaper; however, if the Commission orders the creation of the Community Credit mechanism within the Value Stack, the JU oppose MI's recommendation that its costs be allocated only to residential customers. The JU recommend that CEP's suggestion that the Commission institute a Distribution Planning Advisory Committee be rejected.

The City supports the recommendation to increase the MTC in the Con Edison Service Territory. The MTC has been successful in several utility territories where CDG development has rapidly increased but it has not had the same impact in New York City, where a lack of available space, high real estate and construction costs, and regulatory hurdles (e.g., permitting issues) create barriers to CDG development. To date, Con Edison has only allocated 16.5 MW out of 136 MW in its Tranche 0/1, by far the lowest of all the utilities. The low development rate has resulted in insufficient opportunities for customers located in that region to participate in clean energy. The DER development in New York City is especially impactful for low-to-moderate income customers who oftentimes face greater barriers to clean energy participation than other customers because of issues like creditworthiness, and insufficient marketing and outreach.

The City continues to have concerns that interzonal crediting will incentivize developers to locate DERs in Westchester County. This problem could even be exacerbated by Staff's proposal to increase the per-MWh Tranche 1 MTC value across the entire Con Edison service territory. The City recommends that the Commission bifurcate Con Edison's MTC into separate values for NYISO Zones H/I, and NYISO Zone J. While the City does not propose a specific MTC value at this time, the MTC value for DERs interconnecting in Zone J should be appreciably larger than the new MTC value set for NYISO Zones H and I, such that it overcomes market barriers to DER development in New York City. This would allow customers to realize the perceived benefits of interzonal crediting without further disadvantaging New York City and its residents.

E. Phase One NEM Expansion

Acadia supports extending NEM to small demand-metered non-residential customers.

AGREE recommends an expansion of the Staff's proposal to enable a NEM option for behind the meter projects that are 750 kw or less. AGREE proposes that the NEM option be made available for BTM, remote metered, or CDG, and that the cap be raised to 1 MW. AGREE recommends that this option remain in place until the VDER Phase II process is complete.

CEP strongly supports the application of Phase One NEM to these customers now and beyond January 1, 2020.

CLP believes that NEM provides simplicity and predictability, and suggests that the Commission could define the previous NEM value as the minimum value for all distributed renewable energy projects across the state.

GSS supports the remote net-metering proposal for projects 750 kW and under as it will provide more options to these customers. However, because many customers in this size range are demand-metered, the option to pursue net metering provides minimal benefit to that customer class. GSS proposes to restart projects in this size range which would allow on-site projects to receive the Environmental Value, which should be attached to the overall production of the system, whether used on-site or sent to the grid.

Joint Utilities, in reply comments, agree that expansion of NEM to smaller, demand-billed commercial customers should be adopted because NEM coupled with a demand rate structure not only provides appropriate prices signals regarding the costs such customers impose on the system, but also avoids the potential for significant cost shifts and bill impacts for non-participants.

LISEIA supports Staff's recommendation of exempting systems 750kW. LISEIA notes that its region switched from net metering to VDER on Long Island on May 1, 2018 and it severely hurt the Long Island solar industry and set back the goal of deploying renewable energy in the region. Comparing the 8 months before VDER to the 8 months after VDER, commercial applications has dropped by over 75%. LISEIA recommends a long-term exemption of 750kW and under, and believes that a 3-5 years transition would provide a healthier pathway for growth and deployment of all systems 750kW and under, including CDG, RNM, and residential.

MI opposes Staff's proposal to extend NEM to small, demand-metered, non-residential customers. NEM is in the process of being replaced by the Value Stack because NEM does not encourage the appropriate amount of DER projects required for a clean grid, nor does it support DER projects in a way in which customers (including non-participating customers) would benefit. MI believes that expanding NEM would exacerbate the costs imposed on, and subsidies paid by, non-CDG customers. According to MI, the focus of this proceeding should be on the development of an accurate compensation methodology for DER projects and protecting non-participating customers from having to pay "inequitable and unacceptable" rate increases by phasing-out NEM as opposed to expanding it.

According to MI, non-participating customers finance the subsidies paid to mass-market customers partaking in NEM, and that the Commission has concluded that "continuation of NEM is inconsistent with REV, Commission policy, and the public interest," and therefore ruled previously that NEM should be replaced with a cost-based approach to compensating DER. Because Staff's proposal runs directly contrary to the Commission's prior rulings, MI urges the Commission to reject Staff's proposal to expand NEM to small, demand metered, non-residential customers. MI states that, if the Commission elects to act contrary to its own prior rulings by extending NEM, it should, at a minimum, ensure that such a decision does not result in any incremental costs being imposed on large non-residential customers, who are and would remain ineligible for NEM.

OGS submits that the time has come to address compensation for BTM DER. As currently structured, a BTM DER is not compensated in the same way as an identical CDG project. Under MHP pricing structures, a large customer has no incentive to support development of a BTM project for onsite consumption. The only benefits the customer would realize currently is the avoidance of the NYISO LBMP and certain NYSERDA fees. By contrast, signing up as an anchor customer for a CDG project could provide significantly higher compensation.

PSEG views this change as supporting the State's ambitious carbon emissions and renewables goals. PSEG notes that its tariff currently includes a similar limitation in terms of annual output for NEM projects of less than or equal to 110% of the customer's annual usage. This allows for customers to add projects that anticipate the customer's future growth needs.

Solstice and the **EDA**, urge the Commission to overhaul the state's disastrous VDER policy. The VDER policy is slowing or stopping the development of community solar projects in many New York communities. Solstice believes that Staff's proposals do not go nearly far enough to guarantee resident or businesses to participate in a community renewable energy project. Solstice believes that the previous NEM value provided a level of simplicity and predictability, and thus should be used as the minimum value for all distributed renewable energy projects across the state.

Sullivan Alliance urges the Commission to reform VDER so that it provides a stable, predictable and fair value for community renewable energy generation. The previous NEM provided simplicity and predictability and thus should be used as the minimum value for all distributed renewable energy projects across the state.

SunCommon believes that the extension of Phase One NEM to projects up to 750 kW should apply to smaller RNM projects. It is common for farms and smaller commercial customers to have multiple meters on site, and for the best location to site a solar system to not be where the load of highest interest to the customer is. For example, a meter may be on a barn with small load, while the farmhouse is surrounded by trees and yet has its own meter. It does not make sense to exclude customers from the proposed extension of Phase One NEM solely because their metering situation or site layout makes RNM a more cost-effective option. It would be entirely reasonable to differentiate between RNM situations based on the proximity of the host and its satellites.

According to SunCommon the CDG market is segmenting, with larger 2 to 5 MW projects in development, along with smaller 200 kW to 750 kW projects. The smaller projects serve a unique market need for close-to-community solar, in downstate areas where larger projects cannot be permitted due to local zoning laws, small lot sizes, scenic view sheds, and other restrictions. Smaller CDG systems, sometimes only an acre in size, can be very appealing to many communities and are in alignment with state policy goals. These smaller CDG projects, however, incur higher per unit permitting, development, interconnection, and EPC costs. Special CDG compensation mechanisms should be implemented for a limited time to help encourage the development of the market for these smaller close-to-community CDG projects.

The Board states that the transition from NEM to VDER has placed into jeopardy a portfolio of nearly three dozen municipally driven community solar projects in their region. The Board states that the projects were originally modeled under NEM, and would prefer a return to net metering as the compensation method for distributed renewable energy.

The City believes that the Commission should adopt Staff's recommendation to extend Phase One NEM to demand-metered non-residential customers.

F. Other Issues

1. Reallocation of Queue Positions

AMP believes there continues to be too much emphasis placed on tranche activity as a measure of success in VDER, while in fact there has been comparatively little construction. AMP sees that the greatest barriers to CDG implementation remain customer subscription and financing, which are driven by the value a project can deliver to its customers and financiers. AMP is concerned that all of the Tranches established by the VDER Order, with the exception of those in Con Edison's territory, may be full before broad consumer uptake of CDG statewide is established. Clarity is needed regarding what happens to the MTC/Community Credit value associated with projects which fail to make progress and are removed from the queue by the interconnecting utility. AMP requests that the Commission clarify that the full 2% net-revenue impact established by the VDER Order will be available to CDG projects over time, and that MTC value associated with projects that are removed from the queue will be reallocated to successive tranches.

CEP in its reply comments disagrees with Joint Utilities position that the current VDER tariff is driving rapid solar developments and is successful based on the size of the current interconnection queue. CEP recommends that using actual operating projects or projects that have reached permission to operate is a less speculative measure of success or failure. CEP argues that the solar installation rate in no-residential sector that is subject to VDER is much lower than the multi-gigawatt number touted in the JU testimony. CEP points out that community solar projects and other similarly-sized solar installations still remain a very small portion of the statewide solar market in part because of the VDER tariff.

2. VDER Process

AGREE argues that the VDER Phase II process has been mired in inefficient process, siloed conversations, and a feeling like we are just spinning our wheels. Therefore, AGREE urges the Commission to reset the VDER Phase II process with clear directives on the goals of the process, the kinds of values that should be considered for inclusion in the stack, a timeline, and a well facilitated process.

BRSC believes the VDER process has complicated developing community projects and it should be replaced.

EDA and **CLP** claims that the VDER policy is slowing or stopping the development of community solar projects in many communities. The EDA believes the modest changes proposed in the Staff whitepaper do not go far enough.

MSSC urges the Commission to adopt an order in the near term that will implement the recommendations set forth in the white papers, giving the market short-term certainty and allowing these projects to move forward. Further the MSSC states that it is unlikely that soliciting further feedback in the form of technical conferences or additional whitepapers will provide additional clarity or consensus on the best path forward, nor it is likely to address concerns or issues that have not yet been raised or addressed and any further delay could impact New York's ability to achieve its ambitious clean energy and climate goals.

3. Low-to-Moderate Income Customers

AGREE believes that while the whitepapers propose some modest improvements to the Value Stack that will help community solar projects move forward, even with the changes proposed, community solar for LMI households and environmental justice (EJ) communities will not be addressed. AGREE believes that NYSERDA's Solar for All program is a very narrow solution that has yet to deliver even the modest amounts of renewable energy it promises to most customers. Despite the name "For All" in the title, customers in Con Ed territory and some parts of National Grid territory have no projects available in their region. AGREE encourages the Commission to direct NYSERDA to enact such a program in consultation with community-based organizations and low-income customers and customers living in EJ communities.

Also, credit barriers continue to stymie participation in CDG projects by customers who have low or no credit. The Commission could make great strides in remedying this situation by directing the utilities to implement Consolidated Billing with Purchase of Receivables. The Commission has expressed support for consolidated billing. On September 14, 2017, the Commission Ordered the utilities to file a report within 60 days outlining the costs, practicality, and timeline for implementing consolidated billing within 1 year. A Commission Order from January 2018 references the "Commission's pending consideration of methods to further reduce development costs, including consideration of increased maximum project sizes and consolidated billing." Yet a year later, the Commission still hasn't acted to implement consolidated billing. AGREE encourages the Commission to do so now.

CLP believes the Commission should do more to encourage and enable low-income communities and those of color to take advantage of these opportunities. CLP asks for the creation of a comprehensive program to ensure equitable participation in community renewable energy development by LMI customers. CLP recommends allocating sufficient funding to support distributed renewable energy generation to projects led by, owned by, and serving these populations.

EDA urges the creation of a comprehensive program to ensure equitable participation for low-income and moderate-income and communities of color in community renewable energy development.

Solstice argues that NEM provided a level of simplicity and predictability and thus should be used as the minimum value for all distributed renewable energy projects across the state. Solstice urges the Commission to create a comprehensive program to ensure equitable participation for low-income and moderate-income customers and communities of color in community renewable energy development. The Commission must recognize that most low-income people rent their homes, and tenants must be treated equally, even when they do not pay their utility bills directly, e.g. master-metered buildings, sub-metered. The goal should be that by 2025, 400,000 households from disproportionately impacted communities become renewable energy producers, through community renewable energy projects.

Sullivan Alliance urges the Commission to create a comprehensive program to ensure equitable participation for low-income and moderate-income customers and communities of color in community renewable energy development. According to Sullivan Alliance, VDER is not working well, and that the EDA and its collaborators have suggested specific ways over the past 2-3 years for the Commission to change VDER.

II. Whitepaper Regarding Capacity Value Compensation

A. Alternative 1 Capacity Value

CEP supports the general structure of the proposed Alternative 1 compensation methodology. However, CEP has concerns regarding the definition of peak hours, the calculation of the ICAP tag, and avoidable reliability-related capacity costs that appear to have been excluded from the proposed approach. Staff proposes to base the ICAP tag on generation during the peak summer hours between 1 PM and 6 PM on non-holiday weekdays from June 24th to August 31st. These dates appear overly restrictive. Two of the past 15 peak days have occurred in early June (both in 2004 and 2008), and one of the peaks in the last 5 years occurred in September. Therefore, CEP recommend extending the performance period at least to June 1. This would also be consistent with NYISO's definition of the summer peak period.

Joint Utilities argue that the Alternative 1 rate calculation should use actual monthly kWh instead of the levelized monthly kWh. A levelized monthly kWh (equal to total annual kWh solar generation divided by 12) does not account for seasonal variation in solar output, and will result in rates which are higher when monthly solar output is above average (the summer months), and lower when monthly solar output is below average. According to the provided generation profiles, 64 percent of annual solar production occurs in the NYCA Summer Capability period (May through October) and 36 percent occurs in the Winter Capability period (November through April). Compounding this differential is the fact that ICAP rates are typically much higher in the Summer Capability period than in the Winter Capability period. Approximately 75 to 95 percent of annual ICAP costs are recovered in the Summer Capability Period with the remainder in the Winter Capability Period. By spreading the monthly $/kW avoided ICAP costs over a levelized kWh to determine volumetric $/kWh ICAP rates, Alternative 1 will always yield higher compensation than actual avoided costs.

Further, applying rates based on a levelized kWh to seasonal kWh production will artificially inflate the summer ICAP credit and artificially deflate the winter credit. For example, the Capacity Whitepaper's proposal results in the same modelled NYCA solar profile receiving 27 percent higher compensation in Alternative 1 than under Alternative 3, despite avoiding the same amount of ICAP market purchases. Under the Capacity Whitepaper's proposal, Alternative 1 provides more revenue certainty to DER developers by crediting every kWh injected on a volumetric (kWh) basis even though capacity benefits are based on avoided coincident demand (kW); this risk mitigation financed by utility customers should be balanced, if anything, with lower, not higher, compensation.

The Joint Utilities propose Alternative 1 compensation be based on monthly $/kW avoided ICAP costs divided by monthly kWh generation from the assumed profile, which varies by month based on seasonality. This proposal maintains the certainty of Alternative 1 while more fairly aligning compensation with avoided costs.

B. Alternative 2 Capacity Value

AEE Institute supports Staff's proposal to reduce the number of hours eligible for capacity compensation in Alternative 2, although it has concerns about moving the time window earlier in the day. The Staff proposal recommends moving the hours up by one hour to 1-6 pm from 2-7 pm, citing the historical New York Control Area (NYCA) peak system hours. As seen below, the NYISO system peak hour has not fallen between 1-2 pm since 2006, and since that year, has fallen after 3 pm every year. While no ICAP hours have fallen from 7-8 pm, the data is clearly trending toward a later peak than an earlier peak.

Further, current peak demands do not factor in the growing contribution of solar and other non-dispatchable renewables. The emergence of the "Duck Curve" in California has shown the importance of considering net demand (demand net of solar and non-dispatchable renewables) in system planning. As solar penetration increases, shifting some of the solar production to later hours through storage or tracking systems will become increasingly valuable and will slow the development of a Duck Curve in New York. Considering the project development timeline in New York, the Commission should have 2025 in mind as they determine appropriate windows. Moving the hours up from 2-7 pm to 1-6 pm will increase the likelihood that ratepayers will pay for capacity twice, once through VDER for capacity provided from 1-2 pm and again to the NYISO if the NYCA peak is during the 7-8 pm hour. It is also likely to decrease the business case to install storage and tracking systems, which would maximize evening solar production coincident with future system capacity needs. Those systems that do not have tracking or storage systems can choose capacity Option 1, which provides capacity compensation for each kWh, regardless of when it is produced.

Option 2 should support the business case to install storage and tracking systems so that solar systems built today are better positioned to meet expected system capacity needs and mitigate the negative impacts of a "duck curve." Standalone solar project owners should have the option of a 2-7 pm window and that hybrid solar + storage projects have the option of a 3-7 pm window. A 3-7 pm window is likely to capture the peak hour, without unnecessarily de-rating the value of four-hour energy storage systems. A five-hour window is damaging to the business case for storage, without providing a clear benefit to ratepayers.

CEP has concerns regarding this shift in peak period definition. Staff proposes that the ICAP tag and Alternative 2 compensation would be tied to the top 240 – 245 hours each summer (again from June 24 – August 31 during the hours of 1 pm to 6 pm). CEP is concerned that the proposal could significantly weaken the economic justification for installing trackers and energy storage on solar PV systems under VDER. Under the previous 460-hour methodology, the tariff created a meaningful incentive to design new DERs to target generation toward the later hours of the day. Because of the emphasis of the 460-hour methodology on the later hours of the day, this element of the tariff provided a significant incentive to construct PV systems and paired PV + storage systems designed to generate more in the latter part of the day.

However, the potential value of using energy storage to increase PV production during the eligible ICAP Alternative 2 hours would fall significantly under the 245-hour methodology. The reduction in potential value is less when using Staff's alternative 460-hour approach. This reduction in potential value for paired PV + storage systems under the 245-hour approach is due primarily to the shift forward in eligible hours (i.e., moving from 2-7 PM to 1-6 PM), and to the compression of those hours into fewer days of eligible production. It is also due to the change from a customer-rate benchmark, which includes the utilities' full avoidable costs, including reliability reserve margins, to a benchmark based only on the ICAP market clearing price. The change to the ICAP Alternative 2 methodology would mean that more expensive tracking or PV + storage systems would not significantly outperform traditional fixed-tilt system during the eligible hours, thus reducing the benefit of these more expensive technologies.

In addition, data on the NYISO peaks over the last 15 years provides a better justification for a 2 to 7 pm peak than a 1 to 6 pm peak. The peaks tend to occur in the late afternoon, particularly 4 pm. Further, peak load data appears to show a trend toward the later hours of the day over the last ten years. For example, 7 out of 10 of the peak hours from 2009 to 2018 were in hour 16 (4-5 PM) or later. Analysis of the peak hour data shows that the most common value (mode) across both the last 10 years and the last 26 years was the hour beginning 16 (i.e., 4-5 PM). Hour 16 was also the mid-point (median) value observed across both the last 10 and last 26 years. Given that the standard deviation for the data set used by Staff is approximately 1, the first hour in Staff's proposed 245 hour-set (1-2 PM) would be three standard deviations in distance from the mid-point of 4-5 PM, whereas the proposed last hour (5-6 PM) would only be one standard deviation from the mid-point. It appears more reasonable to adopt a range of 2-7 PM, which appears slightly more consistent with the data than does Staff's proposed range of 1-6 PM.

As with DRV credits, the CEP recommends allowing customers to apply credits received under ICAP Alternative 2 evenly across the year. The rationale for allowing such allocation across the year is the same as for DRV credits and provides for an overall better customer experience.

Staff's proposal rightly accounts for several nuances in capacity procured through the wholesale market, including the Locational Capacity Requirement and adjusting for losses. However, market participants may also procure additional capacity if capacity prices are relatively low, due to the slope of the demand curve. This excess capacity above a market participant's minimum requirement is referred to as the "Awarded Excess." The additional capacity procured can be used in other locations to either meet deficiencies or it can be sold to other Market Participants.

In addition, Staff's approach appears to exclude other capacity-related costs that can be avoided by DERs. For example, each utility is required to procure additional capacity to serve its load plus a reasonable reliability reserve. Load reducing resources such as DERs reduce the forecasted load, and therefore the amount of reliability reserve capacity that must be procured. CEP recommends that the ICAP Tag be "grossed up" by these additional avoidable reserve and awarded excess requirements in a similar manner as is done to account for losses. Because the errors in Staff's approach apply to both ICAP alternatives, the Commission should apply the appropriate gross-up for both ICAP Alternative 1 and 2.

NY-BEST agrees with Staff proposal to shrink the measurement window and increase the credit for each kWh. However, the measurement window timeframe should remain 2:00 PM -7:00 PM and that the Commission should adopt an option for hybrid solar + storage and dispatchable resources under Capacity Alternative 2 and DRV to choose a 3:00 PM -7:00 PM calculation window. Staff's proposal to change the timeframe to 1:00-6:00 PM does not accurately reflect the existing, or trending, load shapes and system peaks. Staff's proposal discourages solar + storage systems and incentivizes less flexible systems.

The peak window has been changing over time and moving to later in the day, a trend that will continue and accelerate as increasing amounts of solar come on-line. As renewable energy penetration increases, this shift to later hours will be accelerated. The effect of the higher renewable levels is to shift the peak later in the day into the evening (7 or 8PM). NY-BEST encourages the Commission to adopt an option for projects to opt into a 3:00 PM-7:00 PM calculation window which is later in the day and compressed into a shorter duration. This would provide an additional option for flexible dispatchable resources, without devaluing energy storage. Moreover, this option will help mitigate any negative impacts of a "duck curve" and reduce dependence on inefficient, fossil-fueled plants during the ramping periods.

Peak Power agrees with Staff proposal to shrink the measurement window for Capacity Alternative 2, although there should be a methodology to adjust the 5-hour window every two-years to reflect the highest four hours of usage during the adjustment period. This will ensure that if more solar is adopted and moves the peak to later hours, that the 5-hour capacity window remains relevant.

C. Questions for Stakeholder Comment

1. Did Staff select the correct load shapes? If not, what load shapes should be used?

CEP argues that its member data from its installations in the field, as well as data from NREL's PV Watts calculator, show that the solar generation profiles provided by NYSERDA in its Value Stack Calculator is 40% to 50% too low, due solely to the fact that the solar generation profiles are not adjusted for daylight savings time (DST).

Joint Utilities agree with the Capacity Whitepaper's use of solar generation profiles, but note that since the generation curves are specific to solar generation, they should be used only to determine Alternative 1 and Alternative 2 Capacity Values for solar projects and not generation technologies with different profiles eligible for Value Stack compensation (e.g., fuel cells or wind). Volumetric compensation for solar should not be extended to higher capacity factor resources because that would result in significant over compensation. Common, assumed generation profiles for other Value Stack-eligible technologies should also be established.

The Joint Utilities support a transition to Alternative 3 compensation for all eligible technologies to stimulate DER market innovation and reduce the risk that all customers will overpay for capacity value. DER collocated with onsite load is generally configured to serve on-site load before exporting on to the system. On-site load is likely to be higher than usual during the NYCA peak hour, thereby further reducing exports on to the system at that time. Therefore, these resources are likely to be overcompensated under a volumetric rate based on an export-only solar generation curve, like Alternative 1 or Alternative 2. Customers with load reduced by DER would receive the benefit of a reduced ICAP tag for their lower peak day consumption and a volumetric capacity rate for export, crediting those customers for a benefit already captured behind the meter. Therefore, the Joint Utilities propose that for DER with collocated load where the customer's capacity tag is determined based on actual demand registration, the DER be required to take Alternative 3.

Joint Utilities note that compensation for avoided ICAP market purchases should equate to the customer value that is actually provided. The Capacity Value compensation mechanism under the Value Stack tariff is meant to compensate DER for injections that offset demand at the single hour of the year that determines the amount of capacity that each entity must purchase. If DER production misses the annual NYCA peak by as little as one hour, no ICAP market purchases are avoided. If a DER project is compensated for capacity value when none is provided, customers must purchase the same amount of capacity as they would have but for the project. This makes the use of an assumed solar production profile problematic.

While modeled solar generation profiles can provide useful estimates of solar generation for a particular location and set of project-specific inputs, actual production for any given project will almost certainly deviate significantly from the assumed profile based on any number of variables. For example, actual weather in any hour may differ from the underlying historical trend used in the production model, the actual solar project may be oriented differently than the orientation assumed in the production model, shading from proximate buildings or trees may affect output during certain hours, the project may utilize different technologies or configurations than those assumed, or random events such as system malfunction could prevent the project from generating as expected given the modeled profile. If any of these differences result in less than expected production during the annual NYCA peak hour, customers will pay not only for ICAP market purchases but also for Value

Stack compensation. For similar reasons, a project may generate more in the NYCA peak hour than what is reflected in the assumed profile and should be fairly compensated for the avoided ICAP market purchases provided. If projects are compensated less than the value they provide, there is little incentive for developers to orient, configure, and operate systems in order to actually provide this benefit to the system.

In reply comments, the Joint Utilities state that while the NYISO's rules increase the reserve requirement that all load serving entities have to meet based on excess capacity purchased under the application of the demand curve during each month's Spot Auction, that excess does not increase the capacity payment made to any individual generation resource nor would it be avoidable if the year over year peak load was decreased, which is the net effect of VDER injections coincident with the New York Control Area peak. Therefore, while the excess capacity is a cost to load, it is not avoidable from a decrease in aggregate load.

2. If Staff's (or a similar) approach is adopted, should it rely on NYISO monthly spot prices or NYISO 6-month strip prices?

Joint Utilities support using the NYISO ICAP Monthly Auction pricing as the basis for avoided capacity rates. In contrast, the Spot Market Auction results are posted as late as the day before the capability month and do not provide ample time for the requisite three-day VDER Credit Statement posting requirement and the Strip Auction results will not capture any month to month price changes.

PSEG recommends using NYISO monthly Spot Market prices for two reasons: (1) The monthly Spot Market Auction is a mandatory auction for Load Serving Entities (LSEs) and incorporates all previously sold, as well as available resources, into its price determination (2) Forecasts/market expectations for monthly Spot Market prices generally establish the market indices against which all forward capacity markets (strip, monthly and bilateral) will trade against. Importantly, the 6-month Strip Auction is not a mandatory market and generally only clears a fraction of the volume that is seen in the subsequent monthly Spot Market Auctions. Moreover, on Long Island (Zone K), relatively few resources have participated in the Strip Auctions. Low volume transactions may result in volatility and incorrect market signals which may not he indicative of current market prices.

3. Should projects that have already qualified be grandfathered? If so, should they be allowed to "opt in" to a new ICAP method, recognizing that Market Transition Credit (MTC) values were based on prior ICAP estimates?

CEP recommends that the Commission allow any project that made its 25% interconnection payment prior to the issuance of the Capacity white paper (i.e., prior to December 12) to remain on the old methodology for ICAP Alternative 2. Failing to do so would create significant hardship for a number of projects and would undermine investors' confidence in New York's DER market at a crucial time for the state's clean energy goals. Specifically, we recommend that the Commission allow legacy projects to remain on the rate class and 460-hour-window that were in effect when such projects made their 25% interconnection payments.

Joint Utilities argue that all projects should be compensated with rates that reflect more accurate avoided costs and therefore grandfathering should remain limited. Projects should not be allowed to opt in to any updated compensation levels that would solely increase developer profits at the cost of increased subsidies paid by all customers.

4. Is Staff's selection of critical summer ICAP hours incorrect? If so, explain why and suggest a better alternative.

CEP in its reply comments agrees with the JU that DPS should use more recent data to establish ICAP coincidence.

Joint Utilities note that customers are only able to derive capacity value (which comes in the form of offsetting wholesale purchases of capacity rather than directly selling capacity to the NYISO) from solar projects when production is coincident with the NYCA peak. The Capacity Whitepaper computed a simple average of the amount of solar output that coincided with historical peak hours since 1993. Customer behavior changes have shifted the peak hour to later in the day and as a result the average coincidence of solar production with these peaks has declined due to more limited solar output in the later hours of the day. For example, while on average solar production had a 36.6 percent coincidence with the NYCA peak across the years 1993-1997, the later occurring peaks in 2014-2018 resulted in only a 20.1 percent coincidence.

Given the disparity in solar coincidence over the 26-year timeframe the Capacity Whitepaper analyzes, the Joint Utilities recommend that the ICAP value for Alternatives 1 and Alternative 2 should instead only be based on the data for the most recent five years which more accurately capture the capacity value provided by solar generation. The Capacity Whitepaper’s proposal would result in compensation for solar projects that is not commensurate with the actual capacity value.

Fixing a presumed ICAP coincidence for the life of all projects under Alternative 1 and Alternative 2 introduces additional risk that the projects will be over/under compensated for their contribution to statewide peak reduction. Thus, in addition to basing the assumed coincidence on more recent yearly data, Staff or the utilities should biennially update the assumed coincidence through an established methodology based on results over the most recent five years.

PSEG generally concurs with Staffs selection of critical ICAP summer hours; however, should a similar formulation be used on Long Island, the following modifications would be needed to better align its system peak hours. 1. Maintain the entire month of June in the definition of "Summer Hours". Based on historic data, the system peak on Long Island has previously occurred during the month of June as recently as June 21, 2012, and also on June 10, 2008. PSEG recommends that Staff allow utilities based on their load pattern to include the entire month of June, as we believe that downstate peaks can occur and have occurred during this period in the summer. 2. Maintain the current critical ICAP hours starting at 2:00 PM to 7:00 PM. On Long Island there is a greater possibility of system peak occurring after 6 PM – than before 2 PM - as a result of the residential population density and high humidity levels in our service territory. The higher humidity levels create more air conditioning load later in the day, which coincides with residential customers returning home at 5 PM resulting in air conditioning and cooking loads.

D. Other Comments

Peak Power affirms its support for Capacity Alternative 3 to be available to both intermittent generators and dispatchable technologies under VDER. The VDER Transition Order recognized that the capacity tag approach is the most precise method for compensating distributing generators for utility avoided capacity costs. As a result, we believe that operators should retain the right to choose to be compensated through this methodology.

CEP notes in its reply comments that it is not accurate to say that the existence of large-scale solar facilities demonstrates the health of the distributed market. CEP points out that distributed generation projects have additional costs and benefits per unit of energy generation due to lesser economies of scale and the expense of serving the customer directly. Further, CEP states that the JU comments mischaracterize the cost of NEM and the VDER tariff to date as well as the cost impacts of the whitepaper’s proposed improvements.