

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

ORDER ON PHASE ONE VALUE OF DISTRIBUTED ENERGY RESOURCES
IMPLEMENTATION PROPOSALS, COST MITIGATION ISSUES, AND RELATED
MATTERS

Issued and Effective: September 14, 2017

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At a session of the Public Service
Commission held in the City of
Albany on September 14, 2017

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 an Order on Net Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Phase One Order) in the above-referenced proceeding.¹ The VDER Phase One Order achieved a major milestone in the Reforming the Energy Vision (REV) initiative by beginning the actual transition to compensation methodologies that enable

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

a distributed, transactive, and integrated electric system. The Commission took the first steps in the necessary evolution of compensation for Distributed Energy Resources (DER) from the mechanisms of the past to the accurate models needed to develop the modern electric system envisioned by REV through the development of Value of Distributed Energy Resources (VDER) tariffs. The Commission noted that the focus of VDER Phase One is to take appropriate, reasonable and expeditious initial steps toward more accurate valuation and compensation of DER. Accordingly, Phase One tariffs are expected to provide immediate improvements in granularity in understanding and compensating for the value of DER to the electric system while setting the foundation for continual improvement and revisions that are informed by the experience and insights gained from Phase One and ongoing analysis.

This transition, the Commission explained, will encourage the location, design, and operation of DER in a manner that maximizes benefits and value to the customer, DER suppliers, the electric system, and society while also ensuring the development of clean generation needed to meet the necessary and aggressive goals embodied in the Clean Energy Standard (CES)² and other State initiatives. This transition will also ensure that the values and costs created by DER will be identified, monitored, and managed to ensure that all customers continue to receive safe and adequate service at just and reasonable rates, and that participation in DER markets is open to all customers, including low-income customers. To facilitate this transition, the Commission directed the utilities to develop, in

² Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard (issued August 1, 2016).

consultation with Department of Public Service Staff (Staff) and stakeholders, Implementation Proposals recommending specific calculation and implementation methods and values for Commission approval.

In this Order, the Commission makes the necessary decisions to allow full implementation of VDER tariffs, including the Value Stack compensation methodology. The Commission approves the utilities' Implementation Proposals, with the following modifications based on stakeholder comments and Staff and Commission analysis: (1) existing surcharges and deferred accounting mechanisms should be utilized for recovering VDER costs; (2) all utilities should use Orange and Rockland's peak kW to kWh method for selecting the Service Class from which the Installed Capacity (ICAP) credit is derived; and (3) Market Transition Credits (MTCs) should be recalculated to account for any change in the three-year average ICAP value when a Service Class (S.C.) different from S.C.1 is used. This Order, combined with the VDER Phase One Order, protects nonparticipating rate payers in two ways. First, it assigns the cost recovery for Value Stack payments to those who benefit from this production. Second, the MTC payments, which exceed the Value Stack payments, are provided by a tranche system that is designed to keep bill impacts within a targeted 2% limit.

This Order also addresses several other issues related to implementation of the Value Stack. This Order directs that the environmental value be based on the Clean Energy Standard Renewable Energy Credit (REC) price at the time a developer makes the 25% interconnection payment required under the Standard Interconnection Rules (SIR) or, where no payment is required, signs an interconnection agreement. This Order establishes a process for finalizing rules for interconnection and compensation of projects that pair storage with clean

distributed generation. In addition, the utilities are directed to use a standardized monthly report to provide Community Distributed Generation (CDG) Sponsors, Remote Net Metering (RNM) project hosts, and on-site customers receiving Value Stack compensation with information on their generation and compensation each month.

This Order also initiates processes for implementing measures that will reduce development costs for DER projects, including expansion of maximum project size and consolidated billing systems. The Commission expects to move towards a maximum project size of 5 MW by early 2018. To facilitate the implementation of this change, Appendix A to this Order contains questions for comments related to eligibility and compensation of projects larger than 2 MW. Responses to those questions should be filed by November 20, 2017. In addition, Staff is directed to work with the utilities and developers through the Interconnection Policy Working Group, the Interconnection Technical Working Group, and other forums to identify and consider technical issues and queue management concerns that may arise with the addition of applications for such larger projects to the interconnection process. If Staff determines that modifications to the SIR are necessary for the integration of larger projects into the process, those proposed changes shall be filed by December 20, 2017 for Commission approval.

Finally, the Commission directs each utility to file a report within 60 days of this Order evaluating the practicality, cost, and timeline for implementing billing automation and consolidated billing within 12 months of this Order.

BACKGROUND AND PROCEDURAL HISTORY

As stated in the REV Track Two Order,³ Case 15-E-0751 was established to provide a process for determining the value of DER, for both planning and transactional purposes. After an extensive stakeholder outreach process, the VDER Phase One Order was issued on March 9, 2017, establishing a framework for the transition in compensation methodologies from net metering to a more granular appraisal of the value of DER in order to capture the temporal and locational values created by these systems.

To enable the full implementation of the VDER methodology through the Value Stack, the Commission noted its intention to issue a Value Stack Implementation Order as soon as the Summer of 2017.⁴ During the initial transition period, the VDER Phase One Order directed Staff to engage with utilities and stakeholders to finalize recommendations to implement the new compensation mechanism. The Commission directed utilities to make specific filings and to develop Implementation Proposals in consultation with Staff and stakeholders and file those Proposals for public comment. In order to provide additional transparency and to facilitate third-party contributions in the determination of values, the VDER Phase One Order directed the utilities to file their most recent Marginal Cost of Service (MCOS) studies and workpapers within 10 business days.

The VDER Phase One Order also identified several other issues that required further evaluation and comment. While the VDER Phase One Order established a control to limit bill impacts resulting from the implementation of VDER Phase One, the Commission noted that other mechanisms may be available to reduce project development costs and thus bill impacts. To

³ Case 14-M-0101, Reforming the Energy Vision, Track Two Order at 19.

⁴ VDER Phase One Order at p. 134.

promote soft cost reductions, Staff was directed in the VDER Phase One Order to work with NYSERDA, the utilities, and market participants to develop and file a proposal or proposals, to be considered as part of the Phase One Implementation Order to the extent feasible, for steps that can be taken to reduce, eliminate, or mitigate market barriers for distributed generation.

Each utility was directed to file an Implementation Proposal, by May 1, 2017 for public review and comment, followed by Commission consideration. Staff was directed to work with the utilities and stakeholders to organize consultative meetings in advance of and, as necessary, following the issuance of the Implementation Proposals. Staff hosted technical conferences on April 5 and 6, and June 12, 2017, to address the Implementation Proposals and other issues identified by Staff. At the April 5 and 6 technical conferences, Staff expressed interest in hearing from parties through informal comments, to be submitted by April 17. Informal comments were filed by stakeholders on April 17 and 18 and were considered by the utilities in the development of the Implementation Proposals. On May 12, 2017, the Secretary to the Commission issued a Notice Soliciting Comments Regarding Value of Distributed Energy Resources Implementation Proposals and Cost Mitigation Issues (the Notice). The June 12, 2017 technical conference included presentations from Energy and Environmental Economics, Inc. (E3), a consultant assisting Staff, on its analysis and recommendations regarding the Implementation Proposals. E3's analysis and recommendations were also posted to the Commission's website.

In addition to the Implementation Proposals, issues that were addressed at the technical conference and in the Notice include: (1) methods for compensating projects that pair storage with clean generation, which avoid providing

environmental and market transition credit compensation for bulk system energy; (2) whether the environmental compensation rate for a project should be fixed when that project pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, rather than at the time of interconnection; (3) whether projects with a rated capacity of greater than 2 megawatts (MW) should be permitted to participate in the Value Stack tariff; and (4) whether utilities should be directed to take action to enable consolidated billing.

LEGAL AUTHORITY

As described in the VDER Phase One Order, the Commission has the authority to direct the treatment of distributed energy resources (DER) 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 and the efficiency of the electric system.

NOTICE OF PROPOSED RULEMAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking (SAPA Notices) were published in the State Register on May 9, 2017 [SAPA Nos. 15-E-0751SP4 and 15-E-0751SP5]. The time for submission of comments pursuant to the SAPA Notices expired on July 10, 2017. The Secretary extended the period for submission of comments to July 24, 2017. A total of 18 comments were received on the Implementation Proposals and other issues identified by Staff.

Appendix J to this Order lists the commenters and the short forms of their names used in this Order.

SEQRA SUPPLEMENTAL FINDINGS

In February 2015, in accordance with the State Environmental Quality Review Act (SEQRA), the Commission finalized and published a Final Generic Environmental Impact Statement (FGEIS) that addressed the potential environmental impacts associated with two major Commission policy initiatives: REV and the CEF. On February 23, 2016, the Commission issued a Draft Supplemental Generic Environmental Impact Statement specifically relating to the CES and on May 19, 2016, the Commission adopted the Final Supplemental Generic Environmental Impact Statement (FSGEIS). In conjunction with the REV Framework Order, the Commission adopted a SEQRA Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions and attached to that Order. The SEQRA Findings Statement was based on the facts and conclusions set forth in the FGEIS.

In conjunction with the decisions made in this Order, the Commission has again considered the information in the FGEIS and the SEQRA Findings Statement and hereby adopts a SEQRA Supplemental Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions. The SEQRA Supplemental Findings Statement is attached to this Order as Appendix I. The actions adopted in this Order do not alter or impact the findings statements issued previously. Neither the nature nor the magnitude of the potential adverse impacts will change as a result of this Order. Rather, through this Order, the Commission has taken concrete

steps to transform New York's electric grid into a modern, distributed and increasingly clean system, consistent with the goals of the REV initiative.

DISCUSSION

I. PHASE ONE IMPLEMENTATION PROPOSALS

Each utility complied with the requirement in the VDER Phase One Order to file an Implementation Proposal for public review and comment by May 1, 2017. The Implementation Proposals were required to include:

1. Calculation and compensation methodologies for Demand Reduction Value (DRV);
2. Identification of, compensation for, and MW caps for Locational System Relief Value (LSRV) zones;
3. Proposed methods and values for providing Capacity Values using Alternative 1 and Alternative 2;
4. Identification of average generation profiles for capacity and DRV compensation in projects' first year of operation;
5. Cost allocation and recovery methodologies implementing the principles adopted in this order for each component of the Value Stack, with particular attention to issues associated with capacity compensation;
6. The practicality of allocating and collecting costs associated with DER compensated under Phase One NEM using the principles adopted in the VDER Phase One Order;
7. Proposed accounting transactions and ratemaking treatment related to the implementation of the VDER Phase One Order;
8. Utility processes for managing billing and tracking bill credits;
9. Reporting procedures for tracking progress in Tranches and any other necessary reporting;
10. Draft tariffs stating the Market Transition Charge for the residential and small commercial classes, for each tranche, as described in the

VDER Phase One Order. This filing should include rules on how the MTC, DRV and LSRV will be applied to CDG projects.

A. Calculation of DRV

1. Utility Proposals

The Value Stack offers compensation based on the value that net hourly injections by DER create for utilities, including avoided distribution-level infrastructure costs. Compensation for avoided distribution-level infrastructure costs is provided through the DRV and LSRV. The DRV applies to all projects in a utility's territory⁵ and is based on the utility's average cost of service. The LSRV is specific to projects that, based on their location and characteristics, contribute to meeting a particular utility need and therefore provide a specific, higher value to the distribution system. Utilities were instructed to partially deaverage the DRV by removing the costs related to needs that would be offset by an LSRV when calculating the DRV.

In compliance with the VDER Phase One Order, each utility filed its latest MCOS study. Each utility also, in its Implementation Proposal, described the calculation and compensation methodologies it proposed to use for DRV and LSRV based on its MCOS study. Staff and its consultant, E3, evaluated the difference in methodologies amongst the utilities and the DRVs they derived. The differences in DRV amounts are driven by two factors: (1) differences in methodology and (2) differences in the characteristics, planning standards, and costs of construction within each utility's service territory. Without standardizing the methodology, which is beyond what can be accomplished in Phase One, Staff was unable to determine

⁵ Projects that receive the MTC do not receive the DRV because the MTC reflects, among other things, their contribution to the distribution system.

precisely how much influence each of these two factors have on the studies.

2. Comments

Some commenters, including CPA and Borrego Solar, argue that the DRV is not certain enough to give appropriate price signals to developers. CEP recommend that only previously approved full MCOS values should be used; in particular, they recommend that Central Hudson's DRV should be calculated based on its previous MCOS study. CEP also suggest modifications to the DRV that would have the effect of increasing and fixing the rates for a longer term. They note that lenders and other financial parties will heavily discount or assign no value to components of the Value Stack that cannot be forecasted or predicted. They also suggest that the MCOS studies be standardized for all utilities. CEP argue that the proposed methodologies for calculating DRV should be fixed for the duration of the Phase One tariff. In their comments, the JU propose that a portion of the DRV and LSRV be retained for the benefit of all customers rather than included as compensation for participants. CEP and AEEI argue that this is inconsistent with the VDER Phase One Order and would inappropriately limit compensation.

3. Determination

The Commission concludes that the utilities' MCOS studies and the methodologies in the Implementation Proposals used to calculate the DRV are reasonable. While the Commission agrees that the utilities' MCOS studies and DRV calculation methodologies should be further standardized and improved, the existing studies and methodologies filed by the utilities are appropriate for the calculation of DRV during Phase One. The VDER Phase One Order recognized that the DRV as created by that Order would represent an imperfect proxy reflective of the

limitations of currently available information, and accepted this as an initial step in the evolution from existing compensation methodologies to the fully distributed and transactive grid of the future.

While the comments filed by CEP are well-developed, the Commission does not adopt their recommendations. Many of their suggestions represent attempts to evolve the MCOS studies and DRV methodologies beyond their current state. These recommendations should be evaluated in the Phase Two process, but are premature for consideration in this Order because of the complexity of standardizing and improving these studies. Their recommendation that a previous MCOS study be used for Central Hudson would inappropriately lock in inaccurate numbers. Central Hudson properly based its DRV on the most recent MCOS study, which was developed for use in their Distributed System Implementation Plan (DSIP) filing. The reduction in DRV that results from Central Hudson using this study, rather than a previous study, is not primarily a result of any methodological changes but instead is a result of the fact that system needs have changed since that previous study was conducted, primarily due to Central Hudson's use of non-wires alternatives to meet certain system needs. For that reason, adjusting it as some commenters suggest would result in compensation in excess of the actual avoided costs resulting from the DER and would therefore cause unreasonable impacts on non-participating ratepayers.

While fixing DRV for a project's entire compensation term, as some commenters suggest, may provide developers with greater predictability of compensation, it is contrary to the fundamental nature and intention of the Value Stack, which is designed to reflect actual reductions in utility costs and to allow price signals to encourage efficient design, location, and operation of resources. The DRV is recalculated based on recent

MCOS studies so that it may dynamically evolve as calculation methodologies are improved and as the underlying values themselves change and so that utilities are compensating projects based on their actual impacts on utility costs.

However, the Commission recognizes that some predictability is necessary and appropriate. To provide additional predictability without eroding the design or goals of the DRV, utilities are directed to fix a project's DRV for three years from interconnection at the time that project pays 25% of its interconnection costs, or at the time of execution of a Standard Interconnection Contract if no such payment is required. The DRV should then be adjusted by the utility three years from the contract date to the most recent DRV and every three years for the rest of its term of compensation under the Value Stack. This will also enable utilities to adjust their DRVs more frequently than every three years based on changes in their system needs or in the appropriate methodology without causing excessive movement in compensation. The process for updating the DRVs and LSRVs should be further developed through the Phase Two process.

The Commission rejects the JU's proposal that a portion of the distribution system value created by DER compensated under the Value Stack be retained for all customers instead of being included as part of a participant's compensation. Reducing DRV or LSRV value to share savings is inconsistent with the MCOS and VDER pricing approach. The Commission agrees with CEP that decreasing the compensation provided below the value that DER are actually providing could lead to a suboptimal level of DER deployment.

B. Identification and Calculation of LSRVs

1. Utility Proposals

Utilities were required to include in their implemental Proposal the identification of, compensation for, and MW caps for LSRV zones. The LSRV is an approximate credit for the project's contribution of value to a specific high-value location. The utilities provided the threshold criteria used for determining LSRV areas, and identified initial areas on its system meeting these criteria. The utilities generally used engineering judgment to choose these thresholds.

2. Comments

Some commenters, including CPA and Borrego Solar, argue that the LSRV is not certain enough or of sufficient quantity to give appropriate price signals to developers. AEEI presented concerns about how Central Hudson created its LSRV zones, arguing that the loading thresholds appear to be significantly more tolerant than those used by the other utilities. AEEI also notes that the utilities propose using different timeframes to identify their LSRV areas. CEP argue that standardized methods should be used across all utilities for identifying LSRV zones and determining MW caps. These determinations should be made in a manner consistent with utility practices for new infrastructure upgrades, on a ten-year planning horizon. CEP also argue that there must be a rational and orderly process for projects to reserve a portion of the MW cap and determine when the MW cap has been reached. Moreover, they argue that the MWS should be apportioned to eligible projects based on expected coincidence with the relevant peak.

CORE recommends that the Commission require Con Edison to reinstate an LSRV value for Phase One VDER projects in its BQDM district, direct Central Hudson to maintain an LSRV component for Coldenham and Lawrenceville Substations, and

remove the Central Hudson split savings adjustment. NY-BEST comments that Con Edison's proposed LSRV zones and MW cap limits may fail to capture important upcoming changes to the grid and encourages the Commission to ensure that the utility's plans include mechanisms to reevaluate the LSRV values and locations or adjust the MW caps in relation to major system changes. NYECC and RENBY notes that when MCOS studies are updated, the LSRV may need to be modified.

3. Determination

As with the DRV, the Commission finds that the utilities' proposed methodologies for calculating the LSRV, identifying the LSRV zones, and determining the MW caps are reasonable and appropriate and therefore are approved for Phase One. As with the DRV, variations in the MCOS studies and other methodologies should be analyzed in the Phase Two process, with a goal of improving MCOS studies and LSRV methodology and standardizing them to the extent possible. However, the Commission recognizes that symmetry across all of the utilities in all aspects of the distribution planning methods is not realistic, nor is it necessarily desirable. The evolution of utility planning methods, including integration of DER and increased availability of system information to developers, will be managed in a coordinated manner in the DSIP process and the Phase Two Value Stack Working Group. The Phase Two Process should address coordination between non-wires solutions and the logistics of determining LSRV zones and setting LSRV values and caps.

To provide additional predictability for the LSRV, the utilities are directed to fix a project's LSRV for ten years from interconnection at the time that project pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is

required. In addition, the utilities may adjust their LSRVs, more frequently than every three years, similar to the DRVs, based on changes in their system needs or in the appropriate methodology.

C. Capacity Values

1. Utility Proposals

The VDER Phase One Order requires that utility Implementation Proposals include the methods and values for providing Capacity Values using each of three Alternatives. 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, which will then be applied to all generators in Alternative 1. Alternative 2 is a variant of this method focused on the 460 peak summer hours. Alternative 3 uses a project's assigned New York Independent System Operator (NYISO) ICAP value. Projects employing intermittent technologies, such as solar PV, will be compensated based on Alternative 1 by default, but may opt into Alternative 2 or 3; other projects will be compensated based on Alternative 3.

Each utility filed its proposed methodology for determining the appropriate Service Class for Alternatives 1 and 2 as well as its proposed methodology for converting that Service Class's capacity charge from an annual value to a value applicable to the 460 peak summer hours for Alternative 2. While the utilities proposed several different methods for determining the appropriate Service Class, all of the utilities used the same method to arrive at the appropriate value for Alternative 2. This method arrived at a per kWh value for those 460 hours by determining what that Service Class's per kWh

capacity charge would be if the entire annual capacity cost for that Service Class was collected during those 460 hours.

2. Comments

CEP argue that the Service Classification used by National Grid, Con Edison and Orange & Rockland for determining Alternative 1 is incorrect, and that the methods used for calculating Alternative 2 rates are not high enough and are inconsistent with the "letter and intent" of the VDER Phase One Order. CEP argue that the Commission's intent in the VDER Phase One Order was for the utilities to select a Service Class for Alternative 1 whose expected demand would most closely match up with the expected generation of solar DERs, such that the capacity impacts imposed by that Service Class would most closely track the capacity contributions of solar DERs across all hours of the year. The utilities, according to CEP, instead used a method that selected a Service Class whose demand during peak load hours most closely matched the expected generation of solar DERs during those hours.

CEP argue that the utilities' calculations of Alternative 2 values were inconsistent with the VDER Phase One Order and present their own proposed calculation. They argue that the utilities' calculations fail to meet the intent of the VDER Phase One Order in that the resulting value is not high enough to provide an incentive to developers to use Alternative 2 and design their projects to maximize generation during the 460 hours.

NY-BEST requests that Alternative 3 be modified to include a day ahead scheduling call from the utility, like the calls used in utility and NYISO demand response programs. CEP argue that Alternative 3 is too risky for developers to choose absent low-cost sophisticated dispatch technologies.

3. Determination

All utilities should use the method used by Orange & Rockland to determine the appropriate Service Class for Alternatives 1 and 2.⁶ That method, which looks at peak kW to kWh, yields the most accurate Service Class to use for the ICAP credit. For that reason, it will yield a credit that is closest to the actual ICAP "market value" provided by each generator and thus minimizes the "out-of-market" value and thereby minimizes the impact on non-participating ratepayers. The methods used by the other utilities places placed too much weight on hours irrelevant to capacity costs. Each utility shall use Orange & Rockland's method to choose the appropriate Service Class and include that Service Class in the tariffs filed in compliance with this Order.

Contrary to what CEP state, their proposal for Alternative 2 is not consistent with the language of the VDER Phase One Order. The Order directs that Alternative 2 kWh capacity compensation be based on the hypothetical per kWh capacity charge if the entire annual capacity cost for the relevant Service Class were collected over the 460 hours. The utility proposals perform this calculation. By contrast, CEP's proposal attempts to derive an average monthly demand cost for the Service Class based on daily average peak demand, which bears no relation to how capacity charges are actually

⁶ The appropriate NREL PV profile is used to calculate the average PV kW that occurs during the peak 5:00 pm hour in the summer capability period (i.e. the 17th hour of the day, during all days in May through October). This is compared to the total kWh produced under that same profile for the same period. For Orange & Rockland, this resulted in a ratio of approximately 361 kW to 1,509,369 kWh or, approximately, 1 kW to 4,176 kWh in the summer capability period. This ratio is then compared to analogous calculations for each retail service class. Orange & Rockland found its S.C. 3 to have a ratio that was closest to that from the PV profile.

calculated or billed. Furthermore, CEP would overvalue solar capacity by an order of magnitude because their proposed equation derives a per kW charge and multiples it by 460 hours of per kWh generation. For these reasons, adopting CEP's proposal would result in inaccurate compensation and cause unreasonable impacts on non-participating ratepayers.

CEP argue that one of the intentions of the Commission with respect to Alternative 2 is to provide additional value to encourage generators to take on more risk of performance. Alternative 2 does provide that additional value in the summer hours to encourage generators to perform during hours with a potentially higher value to the utility system. While it may not result in significantly higher value for every generator, its intent is to offer compensation to generators who are able to meet those performance standards, not to simply guarantee a significantly larger payment to all DER regardless of their performance. The Alternative 2 approach used by the utilities is consistent with the VDER Phase One Order and is therefore approved.

However, CEP are correct that, as the capacity value will be based on a different Service Class from the Service Class used as an example in the VDER Phase One Order, the MTC should be recalculated to achieve the VDER Phase One Order's intent of making Value Stack compensation in Tranche 1 approximately equivalent to compensation under net metering for residential and small commercial customers. Therefore, the Commission directs the utilities to recalculate the MTCs to account for any change in the three-year average ICAP value when using a Service Class different from S.C. 1.

Alternative 3 bases compensation on NYISO capacity cost allocation rules, which assign costs based on usage during the peak hour of the year, as determined after the summer

capability period ends. NY-BEST's proposal to include a day-ahead scheduling call from the utility for Alternative 3, similar to existing utility or NYISO demand response calls, cannot be easily achieved in this system because unlike utility demand response program hours, the peak hour cannot be determined ahead of time. The three alternatives were chosen to accommodate different types of developers with various levels of sophistication. If a developer finds Alternative 3 to be too risky, the other alternatives can be selected.

Further refinement of these approaches should be addressed in Phase Two. In particular, the Phase Two Value Stack Working Group should consider how Alternative 3 can be improved and should coordinate with any efforts to consider modifications to NYISO ICAP cost allocation.

D. Average Generation Profiles

1. Utility Proposals

Utilities were required to identify average generation profiles, which would be used for capacity and DRV compensation in a project's first year of operation. Each utility recommended the use of the National Renewable Energy Laboratory (NREL) Photovoltaic Profiles for its service territory filed with the Staff Report and Recommendations⁷ earlier in this proceeding.

2. Comments

No comments on this issue were received.

3. Determination

The utility proposals are approved. The utilities should rely on the filed NREL data for the applicable Value

⁷ Case 15-E-0751, supra, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding (filed October 27, 2016); Copy of Solar Simulations for DPS (filed October 28, 2016).

Stack tariff calculations in a project's first year of operation. That data is attached to this Order as Appendix H.

E. Cost Allocation and Recovery Methodologies

1. Utility Proposals

The utilities were required to describe the cost allocation and recovery methodologies used in implementing the principles adopted in the VDER Phase One Order for each component of the Value Stack, with particular attention to issues associated with capacity compensation.

Con Edison, Orange & Rockland, New York State Electric and Gas, National Grid, and Rochester Gas & Electric proposed adding a new VDER surcharge to collect the costs associated with Value Stack compensation from delivery and/or supply customers. Central Hudson proposed to recover VDER costs using existing surcharge mechanisms.

In addition, some of the utilities requested deferred accounting treatment for any incremental costs associated with implementation of Phase One of VDER. Specifically, Con Edison and Orange & Rockland requested that the Commission authorize deferral of any incremental operation and maintenance costs associated with the implementation of Phase One of VDER, until the next time base rates are set. Further, those companies requested that the Commission authorize deferral of the carrying charges on any incremental capital expenditures that cause the

companies to exceed the net plant targets that were established in their existing Rate Plans.⁸

Staff reviewed the cost recovery proposals submitted by the utilities for each component of the Value Stack and identified that certain aspects of proposals were inconsistent between the utilities with respect to: the types of customers that costs would be allocated to and recovered from; the compensation term lengths for the Value Stack crediting, including the terms for DRV and LSRV; the proposed methodologies used to calculate capacity values; and, the mechanisms proposed by the utilities to recover the costs associated with the Value Stack.

To obtain reasonable consistency of cost allocation and recovery statewide, Staff worked with the utilities to ensure that the Value Stack components are allocated to and collected from the appropriate customers, based on each customer's Service Classification, service type (supply versus delivery) and voltage level. Staff recommends these cost allocation and recovery mechanisms, attached to this Order in Appendix B, be adopted.

The Commission addressed cost recovery for Capacity Value in the VDER Phase One Order by requiring that these costs be collected from the customers who benefit from VDER capacity injections. In their May 1, 2017 filings, each utility proposed to accomplish this by dividing the Value Stack capacity credit

⁸ Case 16-E-0060, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Electric and Gas Rate Plans (issued January 25, 2017); Case 14-E-0493, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan (issued October 16, 2015).

into two components: (1) the so-called "market value" that is calculated as the capacity purchase costs actually avoided due to the injections; and (2) the "out-of-market" capacity costs that is calculated as the (positive or negative) difference between Value Stack payments made for capacity credits and the "market value" of the injections.

With one exception, noted by NYSEG and RG&E in their filing, the "market value" portion of the credit would be collected from all delivery ratepayers, while "out-of-market" portion would be collected from (or credited to) delivery customers within the same Service Classes as the DER subscribers/customers, similar to collection of the MTC. The exception relates to NYSEG and RG&E Mandatory Hourly Price (MHP) delivery customers, who do not receive a benefit from the DER generation at the time of the NYISO peak, and thus will not be allocated any of the market value portion of the capacity credits.

2. Comments

Comments related to these issues were received from five parties. AEEI recommends against identifying the costs in a separate VDER surcharge. AEEI maintains that this is not a fair representation of the value and benefits of DER. Instead, AEEI suggests that any out-of-market costs be recovered within existing mechanisms and surcharges. AEA argues that Con Edison's proposal to include an additional VDER surcharge on customer bills is unacceptable and inappropriate since the Commission previously determined that the Clean Energy Standard's Renewable Energy Credits (RECs) and Zero Emission Credits (ZECs) should not be listed as separate surcharges on a customer's bill.

MI opposes the utilities' proposed methodology to allocate avoided capacity costs to all delivery customers. MI

states that large, non-residential retail access customers pay for capacity via their non-utility commodity suppliers and, therefore, they experience no direct benefits from a utility's reduced obligation to procure capacity. In addition, MI supports the Commission's policy decision that retail access customers should not be responsible for paying for utility capacity cost reductions that do not directly benefit them and suggests that utilities be directed to recover costs associated with avoided capacity from their commodity customers.

NYC recommends that Con Edison modify its proposal to allocate and recover the remaining environmental costs, that is costs above or below the value of actual avoided REC purchases, from full service supply customers, rather than all delivery customers. NYC reiterates the Commission's decision from the VDER Phase One Order that "compensation for environmental values should be recovered from the same customers that benefit from reduced utility purchases of Tier 1 RECs for CES compliance." Because the Clean Energy Standard established per-MWh renewable energy goals for all load serving entities and the costs of compliance with the CES are generally passed through to an LSE's supply customers, NYC argues that it is appropriate to collect the market value of RECs from Con Edison's full-supply customers as part of recovering Clean Energy Standard costs. To the extent that there is a difference between Con Edison's weighted average cost of RECs and the market price of RECs, NYC argues that the difference should be recovered from or credited to full-service supply customers only. In addition, NYC believes the Commission should direct Con Edison to provide more details regarding the costs associated with the implementation of Phase One VDER, require them to clarify how the costs will be recovered from customers, and clarify the process for reviewing the costs to ensure they are reasonable and appropriate.

NYECC and RENY support the concept that when a ratepayer does not derive any benefit from the utility's Value Stack compensation, the ratepayer should not be allocated any portion of the costs.

3. Determination

Consistent with the principles expressed in the VDER Phase One Order, the Commission directs the utilities to recover costs consistent with Appendix B of this Order. A separate recovery mechanism for the energy value component of the Value Stack is not necessary since the energy value is based directly on utilities' avoided purchases from the NYISO energy market. Therefore, a separate recovery mechanism would result in double recovery of energy costs. The utilities should not use any separate recovery mechanism for the energy value component of the Value Stack, since the utilities avoid purchasing energy from the NYISO and having a separate recovery mechanism would double recover energy costs from ratepayers.

The "market value" portion of capacity should be recovered from delivery customers with costs allocated to Service Class based on how the utility allocates ICAP reduction. This is consistent with the directive in the VDER Phase One Order that this should be collected from the customers who benefit from VDER capacity injections. The utilities' proposal is consistent with this directive because MI's statement that only supply customers will benefit from those capacity injections is mistaken. Excluding the NYSEG/RG&E MHP customers noted above, all delivery customers will receive the benefit of reduced NYISO capacity charges deriving from VDER injections. Both non-NYSEG/RG&E MHP customers, and all retail access customers in all territories, have their metered and/or load-shape-derived capacity responsibilities adjusted for the benefits provided by DER injections. To the extent that this

changes in the future for any subset of customers, the cost recovery should be modified commensurately to reflect such a change.

The out-of-market capacity, out-of-market environmental value, and the MTC shall be recovered from all delivery customers with their respective costs allocated to the Service Classes of the subscribers or off-takers who receive the credits, in proportion to the credits members of each Service Class receive.

The "market value" portion of the environmental credit shall be recovered from all supply customers with costs allocated on a per kWh basis. Finally, the costs for the DRV and LSRV shall be recovered from all delivery customers on a voltage-level-specific basis with costs allocated to Service Classes and subclasses using the appropriate demand allocator. For example, the DRV and LSRV transmission costs should be allocated to all delivery customers using the transmission demand allocator, while DRV and LSRV distribution costs should be allocated to all distribution customers using the appropriate distribution demand allocator.

The Commission agrees with AEEI and AEA that a separate VDER surcharge is unnecessary and therefore directs the utilities to use the cost recovery mechanisms provided in Appendix C of this Order, which will result in recovery consistent with the above requirements. In addition, the Commission directs each utility to file monthly tariff statements incorporating the proposed cost recovery modifications as shown in Appendix D, attached to this Order, on not less than fifteen days' notice, with an effective date of November 1, 2017.

During the implementation of Phase One VDER if utilities incur any incremental costs, they should refer to the

terms of their individual rate plans for guidance as to whether deferred accounting treatment is authorized. The Commission agrees with NYC's comments that Con Edison and Orange & Rockland's request for deferred accounting treatment is premature and lacks the necessary detail to determine whether deferred accounting treatment is warranted or appropriate. Therefore, Con Edison and Orange & Rockland's request for approval of deferred accounting treatment at this time is not granted at this time.

F. Phase One NEM Costs

1. Utility Proposals

Utilities were required to explain the practicality of allocating and collecting costs associated with DER compensated under Phase One NEM using the principles adopted in the VDER Phase One Order. Most utilities currently recover costs for net metering via its Revenue Decoupling Mechanism (RDM). A number of utilities argued that it is impractical to recover these costs through the mechanism that will be used for Value Stack compensation due to its complexity. National Grid, for example, states that NEM credits are calculated in a significantly different way than Value Stack credits. A key difference lies in the fact that the hourly metering of net injections is required for Value Stack compensation but not required or used for Phase One NEM compensation. In light of this significant difference, National Grid argues that adopting the allocation and cost principles of the Value Stack does not make sense. Con Edison notes that it may in the future seek to alter cost recovery approaches for NEM to better align with the more granular approach established for Value Stack customers.

2. Comments

No comments on the practicality of allocating or collecting NEM costs were received.

3. Determination

The Commission concludes that it appears to be impractical presently to recover Phase One NEM costs through a mechanism that is similar to the Value Stack approach. For Value Stack compensation, each value is individually identified and calculated; those values can therefore be used by the utilities to assign and recover costs. By contrast, under Phase One NEM, the value of injections is based on the off-taker's Service Class, rather than the calculated value provided to the utility. This process is not conducive to developing specific credits and charges for various values similar to the Value Stack methodology.

G. Accounting and Ratemaking Treatment

1. Utility Proposals

The utilities were required to describe their proposed accounting transactions and ratemaking treatment related to the implementation of the VDER Phase One Order. For the energy value, capacity value, and environmental value, all the utilities proposed accounting transactions that mirror their current accounting treatment for these types of costs. For the demand reduction value, locational system relief value and the market transition credit, the utilities proposed new accounting transactions.

2. Comments

No comments on accounting or ratemaking treatment were received.

3. Determination

Staff has reviewed the accounting transaction and finds them to be consistent with the Uniform System of Accounts (USOA) for Electric Utilities.⁹ The Commission therefore approves the accounting transactions as proposed by the

⁹ 16 NYCRR §167.

utilities, with slight modifications based on Staff's review, as shown in Appendix E of this Order.¹⁰ In addition, each utility shall file, within 60 days, General Accounting Procedures associated with the implementation of Phase One of VDER.

H. Utility Billing and Crediting

1. Utility Proposals

The utilities were required to describe their processes for managing billing and tracking bill credits. Accurate and timely crediting for CDG projects is particularly crucial to the CDG business model and projects' financial viability since CDG sponsors generally do not bill members until those members receive credits from the utility. Delays can consequently cause cash flow issues for projects. The utilities stressed that these billing and crediting processes will continue to be completed primarily on a manual basis, although some utilities are considering billing automation improvements. Most utilities suggest a 12-24-month time frame for the development of extensive automation.

2. Comments

Commenters from the solar industry and CEP recommend that a clear, automated crediting system be required that includes energy output, billing period, and online access. They also recommend that credits be promptly applied to accounts so that CDG Sponsors can bill subscribers expeditiously.

CEP suggest a detailed list of improvements, including extensive automation, online access, and, if needed, a NYSERDA

¹⁰ Con Edison and Orange & Rockland proposed to record the DRV and the LSRV to FERC account 908 - Customer Assistance Expense. The DRV and LSRV more directly benefit the distribution system and therefore this Order modifies the accounting transaction to reflect these costs being recorded to FERC account 588/598 - Miscellaneous Distribution Expense/Maintenance of Miscellaneous Distribution Plant.

RFP for a third-party administrator to manage bill credit calculation and allocation for the utilities. They also suggest improvements and clarifications to CDG credit banking, including: (1) requiring clear communications to CDG providers of the DRV value associated with particular credits so that CDG providers can plan and charge customers appropriately for the credits allocated; (2) credit banking that provides an MTC for credits ultimately allocated to residential or small commercial subscribers; and (3) allowing CDG hosts to allocate banked credits to customers who may not also be receiving credits associated with generation in a given month.

They also suggest the establishment of a Phase One Implementation working group of individuals from utility billing departments and CDG providers that meets every two weeks until the utilities have launched billing solutions that adequately meet the needs of customers, CDG providers, and regulators. They also asked for clarification that Con Ed will net generation, rather than their proposal in their Implementation Plan to separately bill consumption and injections.

AEA recommends that Con Edison's proposal to not put kWh production on members' bills be rejected. Ampion recommends employing 3rd party billing systems due to the low volume presently of CDG projects, and against a state-wide billing system entity.

DSUN argues that the VDER Phase One Order does not distinguish between demand-metered and non-demand-metered CDG Hosts for volumetric crediting for Phase One NEM, and consequently asks for clarification that all Phase One NEM projects will receive volumetric crediting. DSUN also stresses that it is essential for clear communications with subscribers for the CDG Sponsor to understand the billing period to which a credit was applied and to confirm it corresponds with the CDG

Sponsor's expected value. DSUN also requested that the utilities provide access to electronic copies of subscriber bills.

3. Determination

The Commission agrees with DER developers and CEP that a substantial delay between the injection of energy into the system by a DER and the appearance of credits on a customer's bill is not acceptable. In the case of traditional, on-site net metering, compensation appears on the customer-generator's bill immediately following the end of the billing cycle when the energy is generated and injected. While remote net metering (RNM) practices have varied somewhat among utilities, in many cases RNM customer-generators also receive credits on their bill immediately following the end of the billing cycle where the energy is generated and injected, such that those credits can offset consumption during the next billing period.

The Commission recognizes that both CDG and the Value Stack increase complexity for utility billing and crediting, as compared to on-site and RNM projects. This increased complexity stems from the need to apply credits from one project to multiple accounts, which may have different billing cycles, as well as the more detailed, complex, and granular calculations that must be performed for each project. Therefore, the Commission recognizes that, at least in the early stages of implementation, it may not be possible to provide credits in the same immediate matter as was possible under NEM.

However, both transparency and predictability are necessary to ensure that CDG project development is viable and that customers are appropriately compensated. For that reason, within 30 days of this Order each utility shall file a detailed explanation of when and how credits will appear on customer bills. This explanation should ensure that CDG members receive

credits on their bills as soon as practicable following the end of the billing cycle for the account on which the DER is metered. Each utility must either use a process that ensures that each CDG member receives his or her credits no more than two months following the end of the billing cycle for the account on which the DER is metered, or explain why that is not achievable at this time and identify what immediate steps it will take to develop a system that allows for crediting in that timeframe.

Automation will likely prove an important step for ensuring that bill credits are received in a timely and predictable manner while minimizing utility costs. Utilities are therefore required to file, within 60 days of this Order, an automation and billing report, which shall include a timeline for automation implementation, the potential incremental implementation costs, and explicit consideration of using vendors, third-parties, and/or a statewide system. As described below in the Consolidated Billing section, this report must also include an evaluation of the implementation of consolidated billing.

CDG Sponsors must also be provided with timely and detailed information on the compensation provided for their projects' generation each month. The utilities should consider appropriate ways of communicating this information, such as through an online portal, as part of the automation feasibility evaluation report. In the interim, Staff recommends that utilities be required to use a standardized monthly report to provide monthly compensation information to CDG Sponsors, RNM hosts, and on-site projects compensated through the Value Stack. The information to be contained in a standardized monthly report is provided in Appendix F of this Order.

The Commission also clarifies here several issues related to distribution of credits by CDG projects. Before a CDG project enters service, and as necessary thereafter, the CDG Sponsor sends a form to the utility listing subscribers and indicating what percentage of the credits generated by the project should flow to each subscriber. As demonstrated by a Staff filing,¹¹ there are two alternate ways to use this percentage: either by distributing kWh credits to subscribers based on the percentage and then calculating the value of each credit, with mass market subscribers receiving an MTC as part of that value and other customers receiving a DRV (Alternative 1 in the Staff filing); or by calculating the total value of all credits first, with a portion of those credits receiving the MTC based on the percentage of the total project dedicated to mass market subscribers, and then distributing those dollar value credits to subscribers based on the percentage (Alternative 2 in the Staff filing). Alternative 1 ensures that the benefits of the MTC actually flow to mass market customers and is consistent with the common understanding of CDG, where each subscriber receives a stated percentage of the generation. For those reasons, utilities shall use the Alternative 1 methodology in distributing credits to subscribers.

In some cases, the percentages allocated to each subscriber to a CDG project will add up to less than 100%, either because the CDG Sponsor has not yet enrolled a full set of subscribers or because one or more subscriber has left and not yet been replaced. In those situations, the Sponsor is permitted to bank credits, subject to a two-year limitation as described in the VDER Phase One Order. The value of each banked credit should be calculated by the utility based on the Value

¹¹ Case 15-E-0751, supra, Department of Public Service, Methods of Calculating VDER Bill Credit (filed April 14, 2017).

Stack in the month in which it is generated, including the DRV but not including any MTC. The banked credits should be carried forward as dollar-value credits, rather than kWh credits. The banked credits carried over and generated each month will appear on the standardized monthly report provided to the Sponsor by the utility.

The Sponsor may allocate the banked credits to any of its subscribers, including new subscribers, by notifying the utility of the subscribers that should receive banked credits and of the percentage of banked credits that each subscriber should receive. Sponsors are not required to allocate banked credits to all subscribers or to allocate banked credits in the same proportions as monthly generation is allocated. The utilities shall develop a standard form for Sponsors to use for this allocation and file it within 60 days.

Sponsors must ensure that their allocation of banked credits is consistent with the requirement that 60% of a project's credits be allocated to mass market subscribers. In order to ensure consistency with this requirement, any Sponsor that generates or allocates banked credits in a calendar year must file a report by March 31 of the following year explaining how many credits were banked, how many banked credits were allocated, what percentage of that allocation was provided to mass market customers, and what percentage was allocated to large customers.

Furthermore, to ensure transparency to customers, each CDG Sponsor shall send an annual report to each subscriber. The annual report shall be sent for a calendar year by March 31 of the following year. It must include the amount of credits that the member has received, expressed both in kWh and dollars, as well as total amount the customer has paid in subscription fees and any other costs to the Sponsor. Staff shall develop a

standard form for Sponsors to use for this annual report and file it within 60 days.

I. Reporting Procedures

1. Utility Proposals

The VDER Phase One Order required utilities to describe, in their Implementation Proposals, their reporting procedures for tracking progress in Tranches and any other necessary reporting. These reporting requirements are all intended to give the marketplace sufficient notice and pricing clarity to allow for efficient investment decisions to be made. The VDER Phase One Order established reporting guidelines for the Phase One NEM Mass Market MW allocations and the Value Stack Tranches, requiring "regular reporting by the utilities and explicit notice when 85 percent of the allocation is reached" in all Tranches.¹² The utilities are all using websites to notice the 85 percent allocation circuit breaker which triggers further consideration by the Commission. Tariff statements containing Value Stack compensation details will be filed monthly by the utilities.

2. Comments

No comments were received on this issue.

3. Determination

The utilities' proposals regarding reporting meet the requirements of the VDER Phase One Order, and therefore are approved. All utilities have been regularly reporting Tranche information to Staff and through websites, and will be reporting Value Stack component and LSRV capacity information on a regular basis. NYSERDA will be using this information to develop and

¹² VDER Phase One Order at p. 133.

update a Value Stack calculator that will offer information to support project planning.

J. Draft Tariffs

1. Utility Proposals

Utilities were required to file draft tariffs for compensation under the Value Stack, including rules on how the MTC, DRV and LSRV will be applied to CDG projects. Each utility filed the required draft tariffs. Staff reviewed the Value Stack tariff language proposed by each utility and determined that the proposals were inconsistent. Staff worked with the utilities and developed more standardized versions of the tariffs.

2. Comments

No comments were received on this issue.

3. Determination

The utilities must employ the more consistent tariffs developed in conjunction with Staff. While the Commission is aware that each utility's tariffs have their own complexities and variations, the utilities must use consistent terminology and nomenclature to identify the Value Stack components, as well as use the same methodologies to calculate the Value Stack crediting components. The Commission directs the utilities to file tariff amendments incorporating the modifications as discussed in this Order on not less than fifteen days' notice, with an effective date of November 1, 2017. Further, the Commission directs the utilities to file monthly VDER tariff statements incorporating the requirements listed in the template in Appendix G of this Order on not less than fifteen days' notice beginning November 1, 2017. Because these tariffs and statements have been the subject of extensive public project, newspaper publication is unnecessary and is therefore waived.

K. Base Rate Calculations

1. Utility Proposals

The calculation of Con Edison's "Estimated MTC" for Service Class 1 in Appendix A of the VDER Phase One Order included the three-year estimate of the MAC in the "Energy+" line of the estimated "Base Retail Rate." Because the MAC includes many non-energy factors, and because a number of these factors have expired or are expiring, Con Edison concluded that the inclusion of the MAC in the VDER Phase One Order's estimate was erroneous and did not include the MAC when calculating the MTCs for its Implementation Proposal.

2. Comments

No comments were filed on this issue.

3. Determination

The MTC is based on an estimate of the total cost of a kWh for a customer billed on a volumetric basis, including surcharges, going forward. Where a surcharge is expected to continue, it should be included in the calculation of the MTC. At Staff's request, Con Edison provided an estimate of what elements of the MAC are continuing, which is shown below. Consistent with the intent of the MTC, Con Edison's final MTC calculation shall include the estimate for the 59% of the MAC that is "continuing" in the "Base Retail Rate." The Commission directs Con Edison to include in its tariff or statement filing,

as appropriate, the revised MTC calculation with the adjustment for continuing elements of the MAC.

					6/26/2017
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.					
Monthly Adjustment Clause (MAC)					
Summary of Continuing and Expiring Cost Components					
	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>Three Year Average</u>	<u>Percentage</u>
Continuing MAC Components	\$256,421,289	\$305,170,027	\$366,646,466	\$309,412,594	59%
Expiring MAC Components	<u>262,705,980</u>	<u>163,614,767</u>	<u>220,884,430</u>	<u>215,735,059</u>	<u>41%</u>
Total	\$519,127,269	\$468,784,793	\$587,530,896	\$525,147,653	100%

II. OTHER VALUE STACK ISSUES

Several issues were not part of the utility implementation proposals but were noticed for comment along with those proposals on May 12, 2017. Those issues include compensation for storage paired with clean generation and the process for setting the environmental compensation for a project.

A. Compensation for Storage Paired with Clean Generation

1. Background

The VDER Phase One Order determined that storage should be eligible for Value Stack compensation when paired with eligible generation and addressed the issue of compensating projects that pair storage with clean generation, to avoid providing environmental (E value) and MTC compensation for non-clean energy. The Order concludes that a project that includes energy storage paired with an eligible resource will be eligible for compensation under NEM, for mass market on-site projects, or the under the Value Stack. Staff's original proposal in the Staff Report and Recommendations limited the environmental and MTC compensation for energy storage to net monthly injections to avoid inappropriately providing compensation for those elements for non-green energy stored and then discharged. The Commission

rejected this proposal and noted that such restrictions may not be reflective of expected storage installation configurations. As part of the development of the final Value Stack tariff, Staff was directed to work with stakeholders to identify an option for including energy storage in the Value Stack that avoids permitting uneconomic arbitrage while better reflecting actual storage configurations and value.

2. Comments

CORE recommends that the Commission qualify energy storage as an eligible Tier 1 resource for Phase One VDER and not await Phase Two. CPA believes that energy storage, paired with combined heat and power (CHP), will be a prominent contributor to achieving REV objectives if allowed to do so, and that methods for compensating such resources under the Value Stack compensation approach should be developed and implemented. CPA also recommends that rules be developed that ensure injections from batteries charged with emitting resources receive an appropriate level of the environmental component of the Value Stack. NY-BEST is concerned that the compensation associated with the proposed VDER Value Stack is insufficient to support significant deployment of energy storage. Without some reasonable level of revenue certainty, NY-BEST argues, DER projects will likely not be built and the State will not realize the goals of REV. NYECC and REBNY support not only the pairing of storage with clean generation, but also expediting stand-alone energy storage projects within the VDER Phase One tariff as well as other methods encouraging integration of storage.

The JU proposed in their comments a detailed plan to prevent non-renewable injections from receiving the environmental value. The JU see significant limitations in the assumption that the availability of federal tax credits assures that most paired storage systems are charged exclusively with

renewable resources, when they may not be. They suggest the following: 1) For paired systems able to demonstrate that they exclusively charge storage with clean energy from eligible DER, all compensation could be based on hourly net injections measured at the customer meter; 2) For paired systems able to demonstrate that appropriate controls are in place to assure that injections are only made with the storage off-line, all compensation could be based on net hourly injections measured at the customer meter; 3) For paired systems with a separate revenue grade interval meter and appropriate telemetry on the storage system, the environmental and MTC credits could be determined by the utility reducing the net hourly injections measured at the customer meter by any discharge recorded on the storage system's meter in the applicable interval; 4) For all other paired systems, the utility would base the environmental and MTC credits on netting all injections and withdrawals over the applicable billing period (e.g., monthly) for the project which was Staff's proposal as referenced in the VDER Phase One Order.

3. Determination

In principle, the utility proposals meet the needs and goals expressed in the VDER Phase One Order but the Commission defers final approval of any or all of the four approaches. Significantly, the utility proposals present different methods of determining value and compensation based on different technical system designs. Some further analysis, particularly of the technical aspects of those methods, is appropriate.

Moreover, while the eligibility of storage paired with generation for Value Stack compensation has been approved, it is clear that a number of issues remain that need to be addressed before Value Stack compensation for projects that include storage can be effectively implemented. These include

establishing the appropriate mechanisms in the SIR for the treatment of such projects in the interconnection process, defining necessary technical performance and protection requirements, and determining the appropriate method for identifying the nameplate capacity of a system that combines generation and storage for interconnection and compensation purposes.

Staff is therefore directed to work with NYSERDA, utilities, developers, and other interested stakeholders, through the Interconnection Policy Working Group, the Interconnection Technical Working Group, and other forums to develop a proposal for integrating storage into the interconnection process, which should include consideration of the technical and procedural issues raised by the utilities' compensation options. Staff shall file proposed changes to the SIR and related recommendations by December 20, 2017 for public review and comment followed by Commission consideration.

B. Environmental Compensation (E Value)

1. Background

An additional issue raised in the May 12 Notice that needs to be clarified is whether the environmental compensation rate for a project should be fixed at the commercial operation date or instead should be fixed when that project pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required. Under the current interpretation of the VDER Phase One Order, the environmental value would be based on the REC price on the commercial operation date.

2. Comments

CORE, DSUN, and CEP all recommend that the environmental value should be either based on the REC price at the time a developer makes the 25% interconnection payment or at

the time an interconnection agreement is signed. JU states that either date is workable, provided that it is applied in a consistent manner for all eligible projects rather than as an option for election by the project. Further, the JU asserts the date set by the Commission should also be the date for establishing the LSRV for eligible projects.

3. Determination

Fixing this rate at the commercial operation date would be inconsistent with other aspects of the VDER Phase One Order, including the fixing of the MTC when a project pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required. Furthermore, a delay in fixing this rate until the time of interconnection could reduce the predictability of credit value and therefore impact the ability of the CDG Sponsor to finance the project. The Commission therefore directs that the value be based on the REC price at the time a developer makes the 25% interconnection payment or, where such no payment is required, at the time an interconnection agreement is signed.

III. COST MITIGATION

In the VDER Phase One Order, Staff was directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal for next steps that can be taken to reduce, eliminate or mitigate market barriers, bill impacts, or CDG project costs. Topics in the VDER Phase One Order include development costs, consolidated billing, customer maintenance costs, and interconnection costs.¹³ To the extent feasible, proposals were to be developed for consideration by the Commission as early as part of the VDER Phase One Order.

¹³ VDER Phase One Order at p. 17-18.

Otherwise, the VDER Phase One Order noted, proposals will be addressed by the Commission as they are ready for consideration.

A. Project Size Cap

1. Background

Projects under net metering, as well as under the VDER tariff, are presently limited to a maximum rated capacity of 2 MW. The 2 MW NEM limit is statutorily mandated, while the 2 MW Value Stack limit was included in the Order for consistency with the statutory limit. Projects larger than 2 MW are not eligible for NEM or VDER Value Stack compensation at this time and therefore could not be structured as CDG projects. Furthermore, compensation for such projects would include only what the developer could receive in the wholesale market, for example by selling its energy through the NYISO markets or through utility buyback tariffs using NYISO market prices, and through competitive solicitations, such as participating in NYSERDA's CES Tier 1 auctions to sell its RECs. In many cases, these revenues could be significantly lower than NEM or Value Stack compensation.

The Commission noted in the VDER Phase One Order that DER projects, and CDG projects in particular, benefit substantially from economies of scale, and therefore allowing projects larger than 2 MW to participate in the Value Stack tariff could significantly lower per-MW costs. The Order concluded that considering an increase in project size should be a priority item in the Phase Two process and should be presented to the Commission as expeditiously as possible.

Staff asked stakeholders to comment on whether projects with a rated capacity of greater than 2 MW should be allowed to participate in the Value Stack tariff and if so: whether projects should be limited to a rated capacity of 5 MW or to a different rated capacity; whether the increase in the

capacity limit should be limited to particular technologies or particular project types; and whether the increase in project size should be limited to new projects, or whether it should include (a) existing projects larger than 2 MW that opt-in to the Value Stack and/or (b) existing projects smaller than 2 MW that expand their capacity. Staff stated that allowing projects larger than 2 MW to participate in the Value Stack tariff could significantly lower per-MW costs.

2. Comments

CEP and NYSERDA support a 5 MW cap, but CEP express a preference for a 6 or 8 MW cap which they describe as the size of most larger commercial-industrial scale solar projects in New York today. Other commenters, like CPA, CORE, DSUN, NYECC, and REBNY urge the cap be raised to 15 MW for both existing and new projects. NYECC and REBNY support inclusion of projects for all technologies and product types and existing projects larger than 2MW that opt-in to the Value Stack and/or existing projects smaller than 2 MW that expand their capacity.

NYSERDA explains that in implementing the NY-Sun Program, its experience has been that larger projects can achieve as much as 20% labor and construction cost savings. NYSERDA also stated in its comments that increasing system sizes to 5 MW also reduces administrative costs, not only for the developer but also for the interconnecting utility, compared to multiple adjacent 2 MW projects. Approximately 30% of CDG and RNM projects currently submitted in the NY-Sun incentive program have been subdivided from a larger plot into multiple small ones.

The JU and UIU argue that increasing the cap will produce more ratepayer costs and that VDER compensation is not needed for these larger projects because of lower development costs. They also argue that larger projects enjoy significant

cost reductions, so compensating them at the same rate as smaller more expensive projects will overcompensate the developers and needlessly increase ratepayer costs for these resources.

The JU also argued that the continuation of NEM compensation for the expansion of existing projects is inconsistent with the VDER Phase One Order because it creates a two-tier system that would compensate investments in new projects at a different rate than it would compensate compensation for existing projects that are reconfigured. The JU state that the Commission should address this matter by requiring that compensation for reconfigured projects be based on the current applicable rules for new projects. JU noted technical issues related to increasing the cap, including more distribution-level impacts from larger projects. Any change in existing DER facility design to expand generation capacity, according to the JU, would require re-evaluation of distribution system impacts and possible changes to the distribution system and the DER facility interconnection.

3. Determination

Moving from a maximum capacity of 2 MW to a maximum capacity of 5 MW or, as some parties propose, even larger will come with both costs and benefits to various entities. To ensure that such a transition does not result in increased costs to non-participating ratepayers, while still ensuring that the benefits of economies of scale can be realized, these costs and benefits must be carefully evaluated. Furthermore, the interconnection process must ensure that these projects will not negatively impact utility service or otherwise result in additional costs for utilities. In particular, for these reasons, at this time the Commission will only consider an

increase to 5 MW and not a further increase, as proposed by some commenters, to 6, 8, or even 15 MW.

Increasing maximum project size to 5 MW could significantly decrease costs for some projects, which could permit more projects to be built at a lower cost, benefiting both developers and ratepayers. While increasing system sizes may have limited or no impact on per panel cost, it may have a substantial impact on permitting costs, engineering costs, labor and construction costs, and administrative costs. Projects with a system size of 5 MW can achieve significant economies of scale across soft cost categories compared to small projects, thus allowing more projects to be built at lower compensation levels.

In addition, the subdivision process, used where developers decide to build multiple 2 MW projects adjacent to each other, adds cost and time to the project development process. Moreover, zoning rules in many municipalities require setbacks from all property lines. By subdividing the property, the buildable area is reduced, requiring the acquisition of additional property by the developer to maximize the technical and economic potential of a site. This also increases the land use impact of projects.

As a cost-saving measure, this change would help CDG projects become viable in the later MTC tranches with lower total compensation, and allow RNM projects to move to the value stack methodology. However, larger projects will also have increased impacts on the distribution system. Interconnection considerations for larger projects require more extensive review and consideration. In some areas, it may be impractical or even impossible to sufficiently upgrade the distribution system to handle one or multiple 5 MW projects. The Commission recognizes the distinction between the requirements established in a compensation methodology (i.e. a limit on project size) and the

requirements that determine whether a project can be interconnected. For example, even under the current rules, the fact that a 2 MW project is eligible for VDER compensation does not mean that it is technically possible to connect a 2 MW project at every location. Nonetheless, an increase in the maximum project size to 5 MW should be preceded by consideration to ensure that the interconnection processes are capable of considering all impacts and appropriately assigning all costs.

The Commission recognize that a competitive market environment operates such that a reduction in project costs can be expected to be passed on to CDG subscribers. That said, the current structure of the CDG market warrants consideration whether increasing the cap to 5 MW calls for possible modifications to the MTC for such projects to ensure that savings are shared by developers, particularly in service territories where the Tranche allocations have already been mostly or completely exhausted. If projects up to 5 MW capacity were eligible for the same MTC as projects of 2 MW or less capacity, the policy change could fail to meet its goal of sharing the savings between developers and CDG members, on the one hand, and non-participants through reduced net revenue impacts resulting from the MTC, on the other. In addition, issues related to eligibility require further development, such as whether all VDER-eligible technologies should be included and whether existing projects should be permitted to expand.

For those reasons, while the Commission believes that an increase in maximum project size to 5 MW can be a beneficial change, further process is necessary before it can be finalized and implemented. To facilitate the implementation of this expected increase, Appendix A to this Order contains questions for comments related to eligibility and compensation of projects larger than 2 MW. Responses to those questions must be filed by

November 20, 2017 to guarantee consideration as part of the Commission's deliberations.¹⁴ This will permit a Commission decision by early 2018 on the eligibility policy and rules for projects larger than 2 MW.

In addition, Staff is directed to work with the utilities and developers through the Interconnection Policy Working Group, the Interconnection Technical Working Group, and other forums to identify and consider technical issues and queue management concerns that may arise with the addition of applications for such larger projects to the interconnection process. If Staff determines that modifications to the SIR are necessary for the integration of larger projects into the process, those proposed changes shall be filed by December 20, 2017 for public review and comment followed by Commission consideration.

B. Consolidated Billing

1. Background

Cost-effective consolidated billing represents an important opportunity to reduce soft costs associated with CDG. Furthermore, consistent with REV, it offers an opportunity for utilities to earn fees by providing services to DER markets. Under consolidated billing, the utilities would collect CDG customer payment for subscriber fees, and remit those payments to the CDG provider less any processing fee charged by the utility. In the VDER Phase One Order, the Commission directed Staff to confer with utilities and market participants and evaluate and report to the Commission: whether utilities should enable consolidated billing for CDG projects; the actions

¹⁴ Notices of this consideration and request for comments will be published in the State Register consistent with the State Administrative Procedures Act and in this case's docket.

required to do so; and the conditions required to make such billing work properly and to ensure consumers and ratepayers are appropriately protected.¹⁵ The Commission stated that the evaluation should include consideration of the appropriate roles for the utility and the developer, including in calculations, communications, and collections, with particular attention to relevant provisions of the Home Energy Fair Practices Act (HEFPA), and noted that the utility may be permitted to charge CDG providers for these services, creating a new revenue stream for the utility. Comments on consolidated billing were solicited in the May 12 Notice.

The JU discussed this issue in their Joint Workplan, which was filed April 24, 2017. Con Edison expressed that they do not currently have a large pipeline of CDG projects, and developing a billing system for a small number of projects would be particularly costly on a per project basis. Utility representatives noted that different utilities use different billing systems so developing a state-wide system may be very challenging and time-intensive, compared to the deployment of 3rd party billing systems.

2. Comments

CEP, CORE, DSUN, and the Energy Democracy Intervenors agree that consolidated billing should be required and would provide a needed cost reduction opportunity for developers and a better customer experience overall. The JU is willing to investigate consolidated billing, but warns that costs may be incurred, which they recommend should be borne by the CDG developers. The implementation of consolidated billing would require each utility to make discrete modifications to their billing systems and likely require manually producing bills at

¹⁵ VDER Phase One Order at p. 144.

least at the start of this approach, according to the JU. To the extent that CDG project developers are interested in consolidated billing, each utility would provide estimates of the cost to provide such service and actual activities to implement consolidated billing would commence only after developer commitment to pay the actual implementation and administration costs.

UIU addressed the potential incremental costs utilities may incur associated with developing a consolidated billing system, arguing that at this time there is insufficient information for the Commission to direct utilities to incur the costs associated with developing a consolidated billing system. Further, UIU states that additional detail of costs, benefits, and customer protections should be vetted further to determine if and when consolidated billing would be equitable to all parties.

3. Determination

Consolidated billing has the potential to meaningfully reduce customer management and billing costs for CDG projects while also offering a potential revenue stream for utilities. Indeed, Con Edison's community solar pilot uses a method that mirrors consolidated billing, with customers receiving credits based on the value of the project after costs are netted out.¹⁶ As the utilities describe, implementing consolidated billing will be a complex and potentially costly process and raises some customer protection issues, related to both subscribers and ratepayers more generally.

¹⁶ Case 16-E-0622, Petition of Consolidated Edison Company of New York, Inc. for Approval of a Pilot Program for Providing Shared Solar to Low-Income Customers, Order Approving Shared Solar Pilot Program with Modifications (issued August 2, 2017).

The benefits of consolidated billing, as described by CEP, CORE, DSUN, and the Energy Democracy Intervenors, justify accelerated consideration of the implementation of consolidated billing by the utilities. The automation and billing report, which as described in the Utility Billing and Crediting section above each utility shall file within 60 days of the issuance of this Order, shall include an evaluation of the practicality, cost, and timeline for implementing consolidated billing within 12 months of this Order. The report shall include the potential incremental implementation costs and shall include consideration of using vendors, third-parties, and/or a statewide system. The Commission also reaffirms the VDER Phase One Order's focus on the importance of protecting consumers in a consolidated billing situation. In particular, consolidated billing shall not result in utility shut-offs based on a customer's failure to pay the CDG portion of the bill nor shall it include use of utility collection mechanisms where the CDG portion of the bill is unpaid.

TIMELINE

This section provides a timeline for deadlines and other scheduling matters appearing in this Order.

- October 2017
 - Each utility files detailed explanation of when and how credits will appear on customer bills by October 16, 2017
 - Each utility determines appropriate Service Class for use for capacity Alternatives 1 and 2 and recalculates MTC accordingly
 - Each utility files Value Stack tariffs on not less than fifteen days' notice to become effective on November 1, 2017

- November 2017
 - Each utility files first monthly VDER tariff statements on not less than fifteen days' notice beginning November 1, 2017
 - Each utility files report on automation and consolidated billing by November 13, 2017
 - Utilities file standard form for distribution of banked credits by CDG sponsors by November 13, 2017
 - Staff files standard form for annual CDG sponsor reports by November 13, 2017
 - Comments on policy issues associated with increased project size due by November 20, 2017
- December 2017
 - Staff files proposed SIR changes and related recommendations regarding storage paired with eligible generation and increased project size
- Early 2018
 - Commission decision on eligibility policy and rules for projects larger than 2 MW
 - Comments due on utility automation and consolidated billing reports and Staff proposed SIR changes and related recommendations¹⁷
- Spring 2018
 - CDG Sponsors that operated in 2017 provide first annual reports to their customers by March 31, 2018
 - CDG Sponsors that banked credits or distributed banked credits in 2017 file report by March 31, 2018

¹⁷ Comment due dates will be determined at the time of filing and provided in a Notice.

- Ongoing

- Work in Phase Two to refine and improve the Value Stack, expand VDER eligibility, address rate design issues, and support participation of low- and moderate-income ratepayers in DER programs, with recommendations filed for public review and comment followed by Commission consideration as ready

CONCLUSION

With this Order, the Commission finalizes the VDER Phase One Value Stack such that it is transparent to developers and other interested parties and can be implemented by utilities. As explained in the body of this Order, the VDER system will continue to evolve. In particular, this Order sets the stage for accelerated consideration and implementation of cost-saving measures, including an increase in maximum project size and consolidated billing. Further evolution will occur through the Phase Two process, including increased inclusion of storage and currently non-eligible technologies, refinements in the calculation of values like the DRV and LSRV, and rate design reforms to better reflect system costs and values in both credits for generation and charges for consumption.

The Commission Orders:

1. Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (Orange & Rockland), and Rochester Gas and Electric Corporation (RG&E) (collectively, the Joint Utilities or the utilities) are directed to file tariff leaves implementing the Value Stack consistent with the

requirements in the body of this Order and the below Ordering Clauses on not less than fifteen days' notice to become effective on November 1, 2017.

2. The utilities are directed to file monthly VDER tariff statements incorporating the requirements listed in the templates in Appendices D and G of this Order on not less than fifteen days' notice beginning November 1, 2017.

3. The Demand Response Values (DRVs) and Locational System Relief Values (LSRVs) as proposed in the Implementation Proposals filed by each utility are approved.

4. Each utility shall use the method included in Orange & Rockland's Implementation Proposal to choose the appropriate Service Class for capacity compensation under Alternatives 1 and 2 and include that Service Class in the tariff leaves and tariff statements filed in compliance with Ordering Clause Nos. 1 and 2.

5. The methods for calculating capacity compensation proposed in the utility Implementation Proposals are approved, with the exception described in Ordering Clause No. 4.

6. Each utility shall recalculate the Market Transition Credits (MTCs) for its territory consistent with the discussion in the body of this Order and include those recalculated MTCs in the tariff leaves and tariff statements filed in compliance with Ordering Clause Nos. 1 and 2. Specifically, each utility shall recalculate its MTCs based on the Service Class selected pursuant to Ordering Clause No. 4 and, for Con Edison, based on inclusion of 59% of the Monthly Adjustment Charge (MAC).

7. The average generation profiles proposed for use by the utilities and attached to this Order as Appendix H are approved.

8. Each utility shall use the accounting transactions shown in Appendix E of this Order for credits and debits associated with the implementation of Phase One of VDER.

9. Each utility shall file, within 30 days of the issuance of this Order, General Accounting Procedures associated with the implementation of Phase One of VDER.

10. Each utility shall file, within 30 days of the issuance of this Order, a detailed explanation of when and how credits will appear on customer bills. Each utility must either use a process that ensures that each customer receives his or her credits no more than two months following the end of the billing cycle for the account on which the distributed energy resource (DER) is metered, or explain why that is not achievable at this time and identify what immediate steps it will take to develop a system that allows for crediting in that timeframe.

11. Each utility shall file, within 60 days of the issuance of this Order, an automation and billing report, which shall include a timeline for automation implementation and the potential incremental implementation costs, as well as an evaluation of practicality, cost, and timeline for implementing consolidated billing within 12 months of this Order. The report shall include consideration of using vendors, third-parties, and/or a statewide system.

12. The utilities shall use a standardized monthly report to provide monthly compensation information to Community Distributed Generation (CDG) Sponsors, Remote Net Metering (RNM) hosts, and on-site projects compensated through the Value Stack. The information required to be contained in the standardized monthly report is provided in Appendix F of this Order.

13. Utilities shall allocate credits to CDG subscribers employing the percentages provided by CDG Sponsors by distributing kWh credits to subscribers based on the

percentage and then calculating the value of each credit, with mass market subscribers receiving an MTC as part of that value and other customers receiving a DRV.

14. The value of credits banked by a CDG Sponsor shall be calculated by the utility based on the Value Stack in the month in which it is generated, including the DRV but not including any MTC. The banked credits should be carried forward as dollar-value credits, rather than kWh credits. The banked credits carried over and generated each month shall appear on the standardized monthly report provided to the Sponsor by the utility.

15. Utilities shall permit CDG Sponsors to allocate the banked credits to any of its subscribers, including new subscribers, by notifying the utility of the subscribers that should receive banked credits and of the percentage of banked credits that each subscriber should receive. Sponsors are not required to allocate banked credits to all subscribers or to allocate banked credits in the same proportions as monthly generation is allocated. The utilities shall develop a standard form for Sponsors to use for this allocation and file it within 60 days.

16. Any CDG Sponsor that generates or allocates banked credits in a calendar year must file a report by March 31 of the following year explaining how many credits were banked, how many banked credits were allocated, what percentage of that allocation was provided to mass market customers, and what percentage was allocated to large customers.

17. Each CDG Sponsor shall send an annual report to each subscriber. The annual report shall be sent for a calendar year by March 31 of the following year. It must include the amount of credits that the member has received, expressed both in kWh and dollars, as well as total amount the customer has

paid in subscription fees and any other costs to the Sponsor. Staff shall develop a standard form for Sponsors to use for this annual report and file it within 60 days.

18. Each utility shall report on Tranche progress and Value Stack components as described in its Implementation Proposal.

19. Staff shall file proposed changes to the Standard Interconnection Requirements (SIR) to include necessary provisions for the interconnection of storage paired with eligible generation, as well as any related recommendations, by December 20, 2017.

20. The Environmental Value for an eligible project compensated based on the Value Stack shall be set for the 25-year term of Value Stack compensation at the latest Tier 1 REC procurement price published by NYSERDA at the time the project's developer makes the 25% interconnection payment as required by the SIR or, where such no payment is required, at the time an interconnection agreement is signed.

21. Staff is directed to work with the utilities and developers through the Interconnection Policy Working Group, the Interconnection Technical Working Group, and other forums to identify and consider technical issues and queue management concerns that may arise with the addition of applications for projects with a rated capacity of up to 5 MW to the interconnection process. If Staff determines that modifications to the SIR are necessary for the integration of larger projects into the process, those proposed changes shall be filed for Commission approval by December 20, 2017.

22. Interested stakeholders shall file responses to the questions in Appendix A for Commission consideration by November 20, 2017.

23. The requirements of §66(12) (b) of the Public Service Law and 16 NYCRR §720-8.1 concerning newspaper publication of the tariff amendments described in Ordering Clause Nos. 1 and 2 are waived.

24. 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.

25. These proceedings are continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

APPENDIX A. QUESTIONS FOR COMMENT REGARDING PROJECT SIZE CAP

As described in the body of this Order, comments are solicited in response to the following questions to facilitate Commission consideration of an increase in the project size cap from 2 MW to 5 MW. Comments should be filed by November 20, 2017.

1. Should the increase in the capacity limit be limited to particular technologies, such as solar photovoltaic (PV) generation, or should it include all eligible technologies?
2. Should the increase in the capacity limit be limited to particular project types, such as Community Distributed Generation, or should it include all project types?
3. Should the increase in project size should be limited to new projects to avoid market disruption and implementation issues?
 - a. Should existing projects larger than 2 MW be permitted to opt-in to the Value Stack?
 - b. Should existing projects smaller than 2 MW be permitted to expand their capacity?
4. How this can be implemented to maximize the benefit to ratepayers, both participating and non-participating, from any cost reductions?
5. Should this be implemented with an auction-type solicitation, similar to that described in the Staff Whitepaper on Community Distributed Generation Compensation After Tranche 3, filed on August 29, 2017 and included in this Appendix as Attachment 1? If so, please consider and comment on auction design issues, as discussed in that Whitepaper.
6. Should projects larger than 2 MW be required to dedicate a certain portion of their project to subscribers with low or moderate incomes?

Attachment 1 to Appendix A
Staff Whitepaper on Community Distributed Generation
Compensation After Tranche 3 (filed August 29, 2017)

As described in Appendix A, this Staff Whitepaper is reprinted here to facilitate comment on issues related to project compensation and auctions with respect to the proposed project size cap increase.

INTRODUCTION AND BACKGROUND

On March 9, 2017, the New York State Public Service Commission (Commission) issued the Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Phase One Order).¹⁸ The VDER Phase One Order directed that the compensation for eligible distributed energy resources (DER) transition from net energy metering (NEM) to the "Value Stack." The Value Stack is a methodology that bases compensation on the actual, calculable benefits that a DER creates. As transitional mechanisms, the VDER Phase One Order established "Phase One NEM," which includes a limited continuation of NEM-style compensation, and the Market Transition Credit (MTC), which is an adder to the Value Stack for mass market customers who are members of CDG projects.¹⁹

In order to manage the impact of Phase One NEM and the MTC on non-participating ratepayers, the Phase One VDER Order established Tranches of megawatts (MW) for Community Distributed Generation (CDG) projects in each utility territory, with

¹⁸ Cases 15-E-0751, et al., Value of Distributed Energy Resources, Order on Net Energy Metering Transition, VDER Phase One Order (issued March 9, 2017).

¹⁹ Mass market customers were defined as customers within a jurisdictional electric utility's residential or small commercial service class that are not billed based on peak demand. Mass market customers with on-site DER also receive the MTC if they opt-in to Value Stack compensation.

projects in Tranche 0 receiving Phase One NEM, and projects in Tranches 1 through 3 receiving a declining MTC.²⁰ The Phase One VDER Order explains that while the transitions from Tranche 0 through Tranche 3 would be automatic as each Tranche was filled, projects would continue to be placed into Tranche 3 if it was filled until the Commission took further action. To facilitate Commission consideration of appropriate action, the VDER Phase One Order instructed each utility to notify the Commission when 85% of the total MW capacity for its Tranches had been allocated.

On April 12, 2017, Orange and Rockland Utilities, Inc. (O&R) filed a letter notifying the Commission that 85% of the total MW capacity for its Tranches had been allocated. O&R has continued to assign projects to Tranche 3, consistent with the VDER Phase One Order. Since receiving O&R's notification, Department of Public Service Staff (Staff) has closely monitored the status of projects in O&R's territory and has considered options for moving beyond Tranche 3. The full capacity allocation for Tranche 3 has now been reached in O&R's service territory and it seems likely that, even if some projects allocated Tranche positions are ultimately not completed, enough will be interconnected to fill the initial allocations to Tranches 0 through 3.

²⁰ In addition to CDG, Tranches 1 through 3 apply to on-site mass market projects that opt-in to the Value Stack. On-site mass market projects that do not opt-in to the Value Stack receive Phase One NEM and are subject to a separate capacity allocation. Options for compensating on-site mass market projects put into service after January 1, 2020 are under consideration in the VDER Phase Two Working Groups. The 85% capacity threshold for on-site mass market projects receiving Phase One NEM has not been reached yet in any utility territory.

This Staff Whitepaper presents options and recommendations for moving beyond Tranche 3. While the need for, and timing of, these options may be impacted by the VDER Phase One implementation issues currently under consideration by the Commission, as well as the final decision of developers to move forward with their projects in Tranches 0 through 3, Staff is issuing this Whitepaper now to provide the opportunity for expeditious consideration of these issues by stakeholders and the Commission and to avoid a delay in moving beyond Tranche 3 that could result in further impacts on non-participating ratepayers or market uncertainty. As described in the Notice Soliciting Comments on Community Distributed Generation Compensation After Tranche 3 issued today, Staff requests that interested individuals and organizations file comments on this Whitepaper by October 30, 2017 and reply comments by November 13, 2017.

NON-RECOMMENDED OPTIONS

Staff considered a number of options for compensating mass market members of CDG projects beyond Tranche 3. While Staff's ultimate recommendation, which includes the use of an auction process to determine a Tranche 4 MTC, is described in more detail in the following section, this section discusses several other options.

Continuing Tranche 3

One option would be for the Commission to merely continue Tranche 3, either by increasing the MW allocation or by officially removing the cap. This approach would have the benefit of encouraging continued development of DER projects in O&R's territory, which would both benefit participants in those projects and support the State's clean energy goals.

However, this option would also impose further, and possibly unbounded, impacts on non-participating ratepayers, without due consideration of whether similar benefits could be achieved at lower costs. The fact that the first three Tranches have been exhausted so quickly suggests that total compensation resulting from the Value Stack plus Tranche 3 MTC in O&R's service territory is still significantly above the compensation required to attract investment. Continuing compensation at that level, without a MW cap, could result in significant and unnecessarily high impacts on non-participant ratepayers. Even if a MW cap were set, retaining the Tranche 3 MTC would result in a higher ratepayer impact per project built than might otherwise be achievable; furthermore, it would only delay, rather than resolve, this issue, which would require a determination as to what should happen once that cap is reached.

Ending the MTC

Another option, which would be consistent with the intention expressed in the VDER Phase One Order to limit impacts on non-participating ratepayers to an annual net revenue impact of 2%, would be to eliminate the MTC and compensate all future projects based only on the Value Stack. This would also be consistent with the ultimate goal of the VDER proceeding to base compensation only on actual values created, rather than on other characteristics of the project like the identity of offtakers.

However, given the significant drop this would represent in CDG compensation, this could completely eliminate viable economic opportunities for further development of CDG in O&R's service territory, to the detriment of both customers interested in participating in CDG and the State's clean energy goals. Furthermore, the MTC was intended to partially compensate for values not currently included in the Value Stack, which will be further developed in VDER Phase Two. As the VDER

Phase Two consideration of the Value Stack has only just begun, Staff is not yet prepared to propose updates or additions to the Value Stack, such that eliminating the MTC could result in at least some CDG projects receiving compensation lower than the values they create.

Establishing Further Declining Tranches

A third approach would be to establish a Tranche 4 with a fixed MTC, and possibly further Tranches as well, using the same principles used to develop Tranches 1 through 3. In this approach, Tranche 4, and potentially Tranches 5, 6, and so on, would be established with a MW cap and an MTC based on a further 5% decrease of total compensation. This method would offer the potential for further development at lower relative ratepayer impact than continuing Tranche 3.

However, this method may still result in a higher ratepayer impact per project than necessary because the choice of a 5% decrease would be administratively established rather than based on actual market need. Given both the quick exhaustion of Tranches 1 through 3, as described above, and the Commission's pending consideration of methods to further reduce development costs, including consideration of increased maximum project sizes and consolidation billing, the MTC necessary to ensure financially viable projects may be substantially lower than what a 5%, or even 10%, reduction from Tranche 3 would yield.

RECOMMENDATION AND ISSUES FOR CONSIDERATION

An alternate option, which will also allow for continued development at a limited ratepayer impact, but will also improve the cost effectiveness of the program, is to establish a Tranche 4 through an auction process. Requiring developers to bid an MTC level, which each would be willing to

accept to develop a fixed amount of Tranche 4 CDG project MWS in O&R's service territory, could provide a number of benefits. First, it would allow developers to rely on the most recent set of facts and knowledge base, as the auction would occur after the issuance of the anticipated order on VDER Implementation. Second, this process would allow the competitive solicitation to reveal the minimum MTC necessary to encourage the development of the next Tranche of CDG MWS. This also allows cost effectiveness, rather than queue order, to determine which projects get selected for the next tranche's rights to MTC compensation.

Staff recognizes that many design parameters would have to be decided before a solicitation could be conducted. Staff proposes to copy the New York State Energy Research and Development Authority's Tier 1 Renewable Energy Certificate protocols, where feasible.²¹ Staff's initial view is that the auction should rank bidders from lowest to highest, but pay all bidders the same "market clearing" MTC for all Tranche 4 mass market MWhs. The "market clearing" level would be set by highest accepted MTC bid, and bids should be accepted up to a 12 MW limit. Staff also proposes that acceptable bids be required to be no more than the Tranche 3 residential MTC.

Some of the design parameters depend on the expected competitiveness of the auction. These include whether the bids should be sealed or public, whether it should be a real-time auction, and whether there should be a limit on the portion of Tranche 4 MWS that any one developer can win. Finally, there are practical issues such as the specific prequalification criteria, deposits, or other commitment mechanisms that should

²¹ Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Implementation Plan (filed March 24, 2017).

be required to enhance the effectiveness of the auction and subsequent development.

After the auction has been completed, Staff should report back to the Commission on the results of the auction and on whether further auctions should be held.

CONCLUSION AND REQUEST FOR COMMENTS

As described in the Notice Soliciting Comments on Community Distributed Generation Compensation After Tranche 3 issued today, Staff requests that interested individuals and organizations file comments on this Whitepaper by October 30, 2017 and reply comments by November 13, 2017. In particular, to enable the development of a robust record for the Commission's consideration, commenters are encouraged to provide detailed responses to the below questions regarding auction design, as well as any of the other issues identified in this document, including:

1. Should any modifications be made to the proposed auction design, including to maximize the cost effectiveness of the auction?
2. Should the auction be designed to accept up to 12 MWs, as recommended above, or should a different size be selected?
3. In order to ensure that bids represent serious commitments without requiring bidders to make excessive investments prior to the auction, what prequalification criteria, deposits, or other commitment mechanisms should be used?
4. How long will it take after a Commission decision establishing auction rules for bidders to prepare for the auction?

5. Are there any other issues that should be considered?

APPENDIX B. COST RECOVERY AND ALLOCATION METHOD

Commission Adopted Cost Recovery and Allocation Method					
Value Stack Component	Compensation Based On	Customer Segment & Allocation	Justification	Recovery Mechanism	Compensation Term
Energy Value	Day-ahead hourly LBMP grossed up for losses	Full service customers; no additional recovery mechanism is necessary since utility avoids purchasing energy from NYISO	Offsets energy purchases otherwise made to serve full service customers	\$/kwh	fixed for 25 years
Capacity Value - Market Value	Monthly NYISO Auction Price	Delivery customers; allocated to service class based on how the utility allocates ICAP	Benefit is realized by all customers across the state with the implementation of the following year's ICAP requirement	\$/kwh or \$/kW	fixed for 25 years
Capacity Value - Out of Market Value	The difference between the market value and the total generating capacity payments made to Value Stack customers	All delivery customers; allocated to service class based on the composition of the subscribers who receive the benefits in proportion to the benefits received	Difference between Value Stack Credit compensation and market value will be recovered from customers within the same SC as the customers receiving benefits from the DG	\$/kwh	fixed for 25 years
Environmental Value - Market Value	Higher of Tier 1 REC price per kWh or Social Cost of Carbon per kWh less RGGI; customers who want to retain RECs will not receive compensation	Supply customers; allocated on a per kilowatt hour basis	Utility's REC obligation is reduced by the RECs produced by the Value Stack qualifying generators	\$/kwh	fixed for 25 years
Environmental Value - Out of Market Value	Difference between compensation and market will be recovered from customers within the same service class as the customers receiving benefits from the DG	All delivery customers; allocated to service class based on the composition of the subscribers who receive the benefits in proportion to the benefits received	Allows utilities to recover costs associated with procuring the RECs	\$/kwh	fixed for 25 years
Demand Reduction Value (DRV)	Compensation based on eligible DG performance during 10 highest usage hours at \$ per kW-year value	All delivery customers on a voltage level basis; allocated to service class by voltage level based on appropriate T&D demand allocators	Project adds value to utility system	\$/kW	Recalculated as needed, but at least every 3 years and fixed for 3 years
Locational System Relief Value (LSRV)	Static rate per kW-year value applied to net injected kW	All delivery customers on a voltage level basis; allocated to service class by voltage level based on appropriate T&D demand allocators	Project adds value to local system	\$/kW	Recalculated as needed, but at least every 3 years and fixed for 10 years
Market Transition Credit (MTC)	Static rate per kWh applied to net injected kWh; steps down by tranche	All delivery customers; allocated to service class based on the composition of the subscribers who receive the benefits in proportion to the benefits received	Intended to compensate for unidentified system values	\$/kwh	fixed for 25 years

APPENDIX C. COST RECOVERY MECHANISMS

Value Stack Component	Service Type	Cost Recovery Mechanisms					
		Con Edison		Orange & Rockland		Central Hudson	
Company Proposed	Commission Adopted	Company Proposed	Commission Adopted	Company Proposed	Commission Adopted	Company Proposed	Commission Adopted
Energy Value*	Supply	Market Supply Charge (MSC)	No separate recovery mechanism	Market Supply Charge (MSC)	No separate recovery mechanism	Market Price Charge (MPC)	No separate recovery mechanism
Capacity Value - Market Value	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	VDER Delivery Surcharge	Energy Cost Adjustment (ECA)	Miscellaneous Charges	Miscellaneous Charges
Capacity Value - Out of Market Value	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	VDER Delivery Surcharge	Energy Cost Adjustment (ECA)	Miscellaneous Charges	Miscellaneous Charges
Environmental Value - Market Value	Supply	Clean Energy Standard Supply (CESS) Surcharge	Clean Energy Standard Supply (CESS) Surcharge	Market Supply Charge (MSC)	Market Supply Charge (MSC)	Market Price Charge (MPC)	Market Price Charge (MPC)
Environmental Value - Out of Market Value	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	Market Supply Charge (MSC)	Energy Cost Adjustment (ECA)	Market Price Charge (MPC)	Miscellaneous Charges
Demand Reduction Value (DRV)	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	VDER Delivery Surcharge	Energy Cost Adjustment (ECA)	Miscellaneous Charges	Miscellaneous Charges
Locational System Relief Value (LSRV)	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	VDER Delivery Surcharge	Energy Cost Adjustment (ECA)	Miscellaneous Charges	Miscellaneous Charges
Market Transition Credit (MTC)	Delivery	VDER Delivery Surcharge	Monthly Adjustment Clause (MAC)	VDER Delivery Surcharge	Energy Cost Adjustment (ECA)	Miscellaneous Charges	Miscellaneous Charges

*Offsets energy purchases otherwise made to serve full service customers

Cost Recovery Mechanisms							
Value Stack Component	Service Type	NYSEG		RG&E		National Grid	
		Company Proposed	Commission Adopted	Company Proposed	Commission Adopted	Company Proposed	Commission Adopted
Energy Value*	Supply	Supply Adjustment Charge (SAC)	No separate recovery mechanism	Supply Adjustment Charge (SAC)	No separate recovery mechanism	Electric Supply Reconciliation Mechanism (ESRM)	No separate recovery mechanism
Capacity Value - Market Value	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates
Capacity Value - Out of Market Value	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates
Environmental Value - Market Value	Supply	Supply Adjustment Charge (SAC)	Supply Adjustment Charge (SAC)	Supply Adjustment Charge (SAC)	Supply Adjustment Charge (SAC)	Clean Energy Standard Supply (CESS) Surcharge	Clean Energy Standard Supply (CESS) Surcharge
Environmental Value - Out of Market Value	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates
Demand Reduction Value (DRV)	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates
Locational System Relief Value (LSRV)	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates
Market Transition Credit (MTC)	Delivery	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Transition Charge (Non-Bypassable Charge (NBC))	VDER Delivery Surcharge	Base Delivery Rates

*Offsets energy purchases otherwise made to serve full service customers

**APPENDIX D. TEMPLATE FOR VALUE OF DISTRIBUTED ENERGY
RESOURCES COST RECOVERY STATEMENT**

[Each utility fills in utility specific information.]

For cost recovery, provide the charges for supply and/or delivery customers by service classification taking service under the Value Stack provision pursuant to [tariff section], Distributed Energy Resources ("VDER"), of Schedule PSC No. [XX] - Electricity.

	Supply Charge
Energy Component (based on published day ahead NYISO hourly zonal LBMP energy prices)	N/A
Environmental Component - market	\$/kWh

	Delivery Charge
Capacity Component - market	\$/kWh or \$/kW
Alternative 1	
Alternative 2	
Alternative 3	
Capacity Component - out-of-market	\$/kWh or \$/kW
Environmental Component - out-of-market	\$/kWh or \$/kW
Demand Reduction Value (DRV)	\$/kWh or \$/kW
Locational System Relief Value (LSRV)	\$/kWh or \$/kW
Market Transition Credit	\$/kWh

APPENDIX E. ACCOUNTING TREATMENT

Accounting Transactions - Customer Credits (Credits to Customers for Acquisition of the Load)			
Energy Value			
All Utilities		Account #	Name of Account
	Debit	555	Purchased Power Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
Capacity Value - Market Value			
All Utilities	Debit	555	Purchased Power Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
Capacity Value - Out of Market Value			
All Utilities	Debit	555	Purchased Power Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
Environmental Value - Market Value			
Con Edison/Orange & Rockland/Central Hudson/National Grid	Debit	555	Purchased Power Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
New State Electric & Gas/Rochester Gas & Electric	Debit	557	Other Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
Environmental Value - Out of Market Value			
Con Edison/Orange & Rockland/Central Hudson/National Grid	Debit	555	Purchased Power Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
New State Electric & Gas/Rochester Gas & Electric	Debit	557	Other Expense
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
Demand Reduction Value			
Con Edison/Orange & Rockland/National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	588/598	Miscellaneous Distribution Expenses / Maintenance of Miscellaneous Distribution Plant
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
CH	Debit	566/588	Miscellaneous Transmission Expense / Miscellaneous Distribution Expense
	Credit	232	Accounts Payable
Locational System Relief Value (LSRV)			
Con Edison/Orange & Rockland/National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	588/598	Miscellaneous Distribution Expenses / Maintenance of Miscellaneous Distribution Plant
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable
CH	Debit	566/588	Miscellaneous Transmission Expense / Miscellaneous Distribution Expense
	Credit	232	Accounts Payable
Market Transition Credit (MTC)			
All Utilities	Debit	908	Customer Assistance Expenses
	Credit	142/232	Customer Accounts Receivable/ Accounts Payable

Accounting Transactions - Recovery of Revenues (Customer Charges)			
Energy Value			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues
Capacity Value - Market Value & Out of Market Value			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues
Environmental Value - Market Value & Out of Market Value			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues
Demand Reduction Value			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues
Locational System Relief Value (LSRV)			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues
Market Transition Credit (MTC)			
All Utilities	Debit	142	Customer Accounts Receivable
	Credit	440-444	Revenues

Accounting Transactions - Deferral Accounting			
Energy Value			
	Account #		Name of Account
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	555	Purchased Power Expense
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Other Regulatory Assets/Other Regulatory Liability
	Credit	456	Other Electric Revenues
Capacity Value - Market Value & Out of Market Value			
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	555	Purchased Power Expense
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Other Regulatory Assets/Other Regulatory Liability
	Credit	456	Other Electric Revenues
Environmental Value - Market Value & Out of Market Value			
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	555	Purchased Power Expense
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Other Regulatory Assets/Other Regulatory Liability
	Credit	456	Other Electric Revenues
Demand Reduction Value			
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	456	Other Electric Revenues
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	588/598	Miscellaneous Distribution Expenses / Maintenance of Miscellaneous Distribution Plant
Locational System Relief Value (LSRV)			
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	456	Other Electric Revenues
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	588/598	Miscellaneous Distribution Expenses / Maintenance of Miscellaneous Distribution Plant
Market Transition Credit (MTC)			
Con Edison/Orange & Rockland	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	908	Customer Assistance Expenses
National Grid/New State Electric & Gas/Rochester Gas & Electric	Debit	182.3/254	Regulatory Asset/Regulatory Liability
	Credit	456	Other Electric Revenues

**APPENDIX F. INFORMATION TO BE CONTAINED IN STANDARDIZED
MONTHLY SPONSORS' REPORT**

**Information to be Contained in Standardized Monthly Sponsors Report - CDG Projects
For Illustration Purposes Only**

Utilities to include the following information in monthly bill inserts for projects receiving Value Stack credits.

Customer Name:	CDG Project ABC
Account Number:	12345678
Start Billing Period:	11/1/2017
End Billing Period:	11/28/2017
Total Net Generation this billing period (kWh)	100,000
Net generation allocated to SC1 satellite accounts	50,000
Net generation allocated to SC2 satellite accounts	10,000
Net generation allocated to demand-metered satellite accounts	35,000
Net generation not allocated to a satellite account (banked)	5,000
Value Stack Components	
Energy Component (\$/kWh)	\$ 0.0400
Capacity Component (\$/kWh)	\$ 0.0100
Environmental Component (\$/kWh)	\$ 0.0200
Subtotal Credit per kWh	\$ 0.0700
Market Transition Credit (MTC) (if applicable)	
MTC SC1 (\$/kWh)	\$ 0.0100
MTC SC2 (\$/kWh)	\$ 0.0125
DRV and LSRV (if applicable)	
Demand Reduction Value (DRV) (monthly lump sum)	\$ 50.00
Locational System Relief Value (LSRV) (monthly lump sum)	\$ 500.00
Total dollar credit from per-kWh Value Stack elements	\$ 7,000.00
Total dollar credit from MTC	\$ 625.00
Total dollar credit from DRV + LSRV	\$ 550.00
Total dollar credit applied to satellite accounts	\$ 7,750.00
Total dollar credit banked on host account this billing period	\$ 425.00
Dollar Credit Carried Over from Previous Billing Period (if any)	\$ -

**Information to be Contained in Standardized Monthly Sponsors Report -
On-Site and Remote Net Metered Projects
For Illustration Purposes Only**

Utilities to include the following information in monthly bill inserts for projects receiving Value Stack credits.

Customer Name:	John Doe
Account Number:	12345678
Start Billing Period:	11/1/2017
End Billing Period:	11/28/2017
 Metered/Billed Usage (kWh)	500
Total kWh Injections from DER	(1,000)
 Value Stack Components	
Energy Component (\$/kWh)	\$ 0.0400
Capacity Component (\$/kWh)	\$ 0.0100
Environmental Component (\$/kWh)	\$ 0.0200
Subtotal Credit per kWh	\$ 0.0700
Demand Reduction Value (DRV) (monthly lump sum)	\$ 10.00
Locational System Relief Value (LSRV) (monthly lump sum)	\$ 5.00
Total credit from per-kWh elements	\$ (70.00)
Total credit from DRV + LSRV	\$ (15.00)

Total Dollar Credit from DER this Billing Period	(\$85.00)	(Total Value Stack Credit per kWh x Monthly kWh Injections) +DRV & LSRV amounts
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Dollar Credits Carried Over from Previous Billing Period (if any)	\$ -
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Credit Applied to Customer Bill		
Total Delivery Charges	\$ 100.00	
Total Supply Charges	\$ 50.00	
Total Miscellaneous Charges	\$ 5.00	
Total Charges	\$ 155.00	
DER Credit	(\$85.00)	
Remit to Utility	\$ 70.00	

Dollar Credits Applied to Satellite Site(s), if any	\$ -
Excess Dollar Credits Carrying Over to Next Billing Period	\$ -

APPENDIX G. TEMPLATE FOR VALUE OF DISTRIBUTED ENERGY RESOURCES VALUE STACK CREDITS STATEMENT

[Each utility fills in utility specific information.]

For customers taking service under the Value Stack provision pursuant to [tariff section], Distributed Energy Resources ("VDER"), of Schedule PSC No. [XX] - Electricity, the credit shall be calculated by summing the Value Stack Components, as applicable, and multiplying the total credit by the net export net hourly injections.

Service Classifications eligible to participate in [tariff section], Value of Distributed Energy Resources ("VDER"):
[Company Name]: [Service class numbers]

	Credit
Average Monthly Energy Component (based on published day ahead NYISO hourly zonal LBMP energy prices) [averaged by zone]	\$/kWh
Capacity Component	\$/kWh or \$/kW
Alternative 1 for Residential and Non-Demand Small Commercial	\$/kWh
Alternative 2	\$/kWh
Alternative 3	\$/kW
Environmental Component	\$/kWh
Demand Reduction Value (DRV)	\$/kWh or \$/kW

Previous year's NYISO Top Ten Peak Hours and Peak Demand (to be filled in with the January statement annually)
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Locational System Relief Value (LSRV) for the following locations:	\$/kWh or \$/kW	MW remaining in LSRV Zone
[Location- ABC]		

	Market Transition Credit \$/kWh	
Tranche	S.C. No. 1	S.C. No. [2] - Non-Demand
0/1		
2		
3		
4		

CASES 15-E-0751 and 15-E-0082

APPENDIX H. AVERAGE GENERATION PROFILE DATA

See "Appendix H Average Generation Profile Data.xlsx" filed on September 14, 2017 in Cases 15-E-0751 and 15-E-0082 in the New York State Department of Public Service Document and Matter Management (DMM) system, accessible at

<http://documents.dps.ny.gov>.

**APPENDIX I. STATE ENVIRONMENTAL QUALITY REVIEW ACT
SUPPLEMENTAL FINDINGS STATEMENT**

September 14, 2017

Prepared in accordance with Article 8 - State Environmental Quality Review Act (SEQRA) of the Environmental Conservation Law and 6 NYCRR Part 617, the New York State Public Service Commission (Commission), as Lead Agency, makes the following supplemental findings.

Name of Action: In the Matter of the Value of Distributed Energy Resources (Case 15-E-0751) Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters

SEQRA Classification: Unlisted Action

Location: New York State/Statewide

**Date of Final
Generic Environmental
Impact Statement:** February 6, 2015

**Date of Final Supplemental
Generic Environmental
Impact Statement:** May 23, 2016

FGEIS available at:

<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101>

FSGEIS available at:

<http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=48235&MNO=15-E-0302>

I. Purpose and Description of the Action.

An order of the Public Service Commission addressing the implementation of more accurate valuation and compensation mechanisms for Distributed Energy Resources (DERs), particularly distributed generation (DG) projects formerly compensated through Net Energy Metering (NEM). The order sets compensation rates and methodologies for DERs in order to fully implement the Value Stack methodology. The order also sets forth a process for finalizing rules for interconnection and compensation of projects that pair storage with clean distributed generation. In addition, further processes for considering and implementing an increase in maximum project size for the Value Stack and

consolidated billing are established.

II. Facts and Conclusions in the FGEIS Relied Upon to Support the Decision

In developing this findings statement, the Commission has reviewed and considered the Final Generic Environmental Impact Statement (FGEIS) in Case 14-M-0101 – Reforming the Energy Vision (REV) and the Final Supplemental Generic Environmental Impact Statement, issued on May 23, 2016 (FSGEIS) in Case 15-E-0302. The findings are based on the facts and conclusions set forth in the FGEIS and the FSGEIS.

The actions described above do not alter or impact the SEQRA findings issued previously. Neither the nature nor the magnitude of the potential adverse impacts will change as a result of the actions described in this order. Rather, in this order, the Commission has taken concrete steps to help further transform New York's electric grid into a modern, distributed, and increasingly clean system, envisioned in the REV Proceeding (see, SEQRA Findings Statement issued in conjunction with the Order Adopting Regulatory Policy Framework and Implementation Plan issued on February 26, 2015, at Appendix B).

APPENDIX J. ABBREVIATIONS USED FOR COMMENTERS

Advanced Energy Economy Institute, Alliance for Clean Energy New York, Inc., and the New England Clean Energy Council (collectively, AEEI)

Ampion

Association for Energy Affordability, Inc. (AEA)

Borrego Solar Systems, Inc. (Borrego)

Consolidated Edison Company of New York (Con Edison)

City of New York (NYC)

Clean Energy Parties - New York Solar Energy Industries

Association, Solar Energy Industries Association, Vote Solar, the Coalition for Community Solar Access, Pace Energy and Climate Center, the Natural Resources Defense Council, and Acadia Center (collectively, CEP)

Consumer Power Advocates (CPA)

Coalition of On-Site Renewable Users (CORE)

Distributed Sun LLC (DSUN)

Energy Democracy Alliance (EDA)

Genesis Industrial Group (GIG)

Joint Utilities - Central Hudson Gas and Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric and Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (Orange & Rockland), and Rochester Gas and Electric Corporation (RG&E) (collectively, JU)

Multiple Intervenors (MI)

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

New York Energy Consumers Council, Inc. (NYECC) and the Real Estate Board of New York (REBNY)

CASES 15-E-0751 and 15-E-0082

New York State Energy Research and Development Authority
(NYSERDA)

Utility Intervention Unit, Division of Consumer Protection,
Department of State (UIU)