

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 NET ENERGY METERING TRANSITION, PHASE ONE OF VALUE OF DISTRIBUTED ENERGY RESOURCES, AND RELATED MATTERS

Issued and Effective: March 9, 2017

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on March 9, 2017

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Gregg C. Sayre
Diane X. Burman, concurring

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(Issued and Effective March 9, 2017)

BY THE COMMISSION:

INTRODUCTION

This order achieves a major milestone in the Reforming the Energy Vision (REV) initiative by beginning the actual transition to a distributed, transactive, and integrated electric system. Our decisions here represent 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 impacts of the electric system on the lives and interests of New York residents are both significant and wide-ranging, from the health, safety, and business needs for secure and reliable energy to the

financial impacts of utility bills to the environmental impacts of the generation of electricity. However, as the Commission has recognized through the REV initiative, many aspects of the electric system reflect legacy policies, technologies, and interests and have not been sufficiently reformed to reflect developments over the past decades, including technological developments, evolving consumer and market interests, and full recognition of environmental externalities. A failure to bring the electric system and industry fully into the modern world and to keep it apace with continuing developments could have disastrous consequences, including a failure to meet modern reliability needs and expectations, enormous and avoidable costs associated with the inefficient replacement of aging components, and unchecked emissions of greenhouse gasses and other pollutants. In addition, DER participation should be open to all customers, including low-income customers, and should be coupled with strong consumer protection measures.

The transition described herein is guided by core principles in the REV Framework Order.¹ First, the unidirectional grid must evolve into a more diversified and resilient distributed model engaging customers and third parties. Second, ensuring universal, reliable, resilient, and secure delivery service at just and reasonable prices remains a function of regulated utilities. Third, the overall efficiency of the system and consumer value and choice must be improved by achieving a more productive mix of utility and third-party investment.

¹ Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2016) (REV Framework Order or Track One Order); Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order).

The Commission also recognizes that existing DER business models are well-established and based largely on net energy metering (NEM). These business models reflect the capabilities and needs of the electric system at the time they were designed and they appropriately served to open up markets and drive initial development. But such business models and NEM in particular are inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers. As such, they are unsustainable. To the degree that they over-compensate DER providers by transferring their fair share of fixed costs onto other customers, they operate now in a manner that will not sustain wide-scale deployment as the inherent subsidies reach a level that is oppressive to non-participants. While it is natural for the existing DER businesses to want to maintain the business models and financial support that they have enjoyed, the public interest requires the development of and prompt transition to more accurate valuation and compensation mechanisms for DER, particularly for project types currently compensated through NEM, that accurately reflect and properly reward DER's actual value to the electric system and that ensure all customers pay their fair share for the costs of grid operation and benefit from the value they provide.

The VDER Phase One tariffs will 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. This transition will encourage the location, design, and operation of DER in a manner that maximizes benefits to the customer, 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) and in this order. 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 ensure that development and interconnection of distributed generation (DG) projects can continue unabated, a transitional period is necessary so that the market and customers can fully understand the mechanisms of and incentives provided by the methodology adopted in this order. During an initial period, commencing with the date of this order, new projects will continue to receive compensation based on NEM methodologies, except that those projects will be limited to receiving such compensation to 20 years before transitioning to new compensation mechanisms; this initial compensation mechanism is described as Phase One NEM in this order. While Phase One NEM contains inefficiencies similar to NEM as a compensation methodology, the term limitation will offer some incentives for developers and customers to consider the impacts of the location, design, and operation of DER on the electric system. Phase One NEM is subject to filing deadlines to ensure that it applies only to projects that are already in advanced stages of development and, for Community Distributed Generation (Community DG or CDG), to a limited capacity allocation to manage any impact on non-participants.

During this initial period, the Department of Public Service Staff (Staff) will engage with utilities and stakeholders to finalize recommendations to implement a new compensation mechanism. Once the recommendations have been filed and received public scrutiny, the Commission will take further action, as early as this Summer, to fully implement compensation for new projects that reflects the values created by those projects in a more accurate and granular manner, described in this order as Value Stack compensation. Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified, the Value Stack will include a Market Transition Credit (MTC) for CDG projects that provides compensation for initial projects that is substantially similar in value to compensation under NEM.

In this order, the Commission (a) adjusts the current interim floating ceiling on new Public Service Law (PSL) §66-j NEM projects by setting a new fixed ceiling that limits the level of new projects in favor of transitioning to a new regime; (b) establishes a VDER Phase One tariff consisting of two components, the Phase One NEM tariff implementing a new DER program similar to NEM with some exceptions, and the Value Stack tariff implementing a new, more comprehensive DER program based on monetary crediting for net hourly injections; (c) establishes capacity-based allocations for mass market and CDG projects intended to limit the potential impacts of the VDER Phase One tariff on non-participants to an incremental net annual revenue impact of approximately 2% for each utility; (d) allocates the costs associated with the VDER Phase One tariff to the customers who benefit from the savings associated with the compensated DER, or where the groups of benefitted customers have not been identified, to the customers within the same service class as

the beneficiaries; (e) allows participating customers to pair energy storage technologies with their eligible projects; (f) directs development of proposals for next steps that can be taken to reduce, eliminate, or mitigate market barriers, bill impacts, and CDG project costs; (g) directs NYSERDA to file new or revised Clean Energy Fund (CEF) investment chapters to support programs aimed to encourage and incentivize low-income customer participation in CDG projects, as well as to support the transition to the Value Stack; (h) directs Staff to consider options to encourage low-income customer participation in CDG including an interzonal CDG credit program and tailored approaches for CDG projects that comprise a majority of low-income off-takers; (i) directs Staff to develop an updated whitepaper on DER oversight provisions; (j) directs utilities to make specific filings to enable the full implementation of the Value Stack tariff; and (k) directs the commencement of VDER Phase Two.

LEGAL AUTHORITY

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

Pursuant to PSL Section 65(1), every electric corporation must safely and adequately "furnish and provide

[electric] service, instrumentalities, and facilities as shall be safe and adequate and in all respects just and reasonable." Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure "for the purpose of . . . furnishing or transmitting electricity." Pursuant to Section 66(2), the Commission may "examine or investigate the methods employed by. . . corporations . . . in manufacturing, distributing, and supplying . . . electricity," as well as "order such reasonable improvements as will best promote the public interest . . . and protect those using . . . electricity." Moreover, pursuant to Section 66(3) the Commission may prescribe "the efficiency of the electric supply system." Accordingly, the Commission has the jurisdiction over the electric utilities affected by this order to require them to comply with the requirements outlined herein.

In fulfilling its statutory mandate, the Commission has approved tariff provisions and established programs governing service, billing, and compensation for various DER, including distributed generation. For example, each electric utility's Commission-approved tariff includes standby rates, which govern service to large customers that meet a substantial part of their electric needs through on-site generation, and buy-back service, which governs the purchase of capacity and energy by the utility from qualifying customers.² Similarly, each electric utility has demand response programs, which offer incentives or compensation for reductions in peak demand,³ and

² See, e.g., Con Ed Tariff, Schedule for Electricity Service, P.S.C. No. 10 - Electricity, leaves 157-170 and 462-477.

³ See, e.g., Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

several non-wires alternative (NWA) programs are under development, offering compensation to DER, including distributed generation, that supports elimination or deferral of costs associated with traditional infrastructure.⁴

As described in Appendix C, The History of NEM in New York, NEM was established by statute in 1997 and subsequent amendments have expanded eligibility and made other minor changes.⁵ The NEM statutes govern compensation and terms of service for customer-generators that interconnect their eligible generating equipment with a utility's system before a rated generating capacity ceiling for that utility's service territory is reached.⁶ Once the ceiling has been exceeded, customer-generators are no longer entitled to be provided service, billed, and compensated based on the terms of the statute. The Commission therefore has not only the authority but also the responsibility to define terms of service and compensation for those customer-generators.

⁴ See, e.g., Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

⁵ NEM of wind turbines is governed by PSL §66-l, while NEM of all other technologies is governed by PSL §66-j. The terms and conditions of NEM under the two statutes are essentially identical, except that wind is subject to a separately calculated statutory cap of 0.3% of 2005 electric demand for each utility, and therefore is not counted towards the cap that applies to all other technologies.

⁶ Technically, the statutes do not create a cap, but rather require that each utility offer NEM to eligible customer-generators until the specified capacity is reached. PSL §66-j(3)(a)-(b). Because utility tariffs have always limited NEM based on the minimum capacity required, that capacity level has generally been described, and will continue to be described in this order, as a cap or a ceiling.

PSL §66-j sets initial ceilings of 1% of each utility's 2005 electric demand and provides the Commission with broad discretion to determine what level of NEM above these ceilings is in the public interest. The Commission raised the ceilings several times and ultimately directed that the ceilings float with interconnections.⁷ However, in the Interim Ceilings Order, the Commission explained that the floating ceilings were a temporary measure and that, when a new compensation mechanism was developed, the ceilings would be set based on the existing capacity levels.

Where, as here, the Commission finds that additional NEM would no longer be in the public interest, we must determine what form of compensation for new DER projects is consistent with our statutory mandates to ensure safe and adequate service at just and reasonable rates consistent with the public interest and the efficiency of the electric system. Consistent with our statutory duties, with ratemaking principles, and with the goals of REV, in this order we create a compensation structure for those projects based on the benefits they create and the costs they impose.

PROCEDURAL HISTORY

As noted in the REV Track Two Order,⁸ Case 15-E-0751 was established to provide a process for determining the value of DER, for both planning and transactional purposes. An extensive collaborative process was established that looked to

⁷ Case 15-E-0407, Orange and Rockland Utilities, Inc. - Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (October 16, 2015) (Interim Ceilings Order).

⁸ Case 14-M-0101, Reforming the Energy Vision, Track Two Order at 19.

market participants and stakeholders to develop proposals. Although there was active participation and collaboration by a wide range of stakeholders and market participants, it became necessary for Staff to offer straw proposals to facilitate the discussion. Staff provided a number of straw proposals intended to explore approaches that reflected the collaborative discussions. Participating parties provided input on the straw proposals at public, noticed collaborative conferences, as well as during smaller breakout groups established to address specific topics within the straw proposals. The process culminated in a Staff Report and Recommendations (Staff Proposal), filed on October 27, 2016.

The Staff Proposal presents several recommendations of general applicability and details the Value Stack as a proposed valuation and compensation methodology, along with when and how that methodology should apply to various market segments. It also describes several unique aspects for transitioning from NEM, including limited continuation of NEM for mass market customers consistent with our REV Track Two Order and an MTC that Staff proposes be made available to certain projects during the transition from NEM. In the context of developing a VDER Phase One methodology and tariff, Staff identified distinctions among four major market segments, including: 1) on-site, mass-market projects and customers, defined as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand; 2) CDG projects and customers, defined as consisting of an eligible generating facility located behind a non-residential host meter and a group of members located at other sites that receive credits from that facility to offset their bills; 3) remote net metered (RNM) projects and customers where non-residential customers, as well as residential customers who own

or operate farm operations, receive credits for excess generation by an eligible generating facility they own, lease, or operate at a site they own or lease, and where those credits are used to offset the bill for meters at one or more other properties that they own or lease; and, 4) large, on-site projects and customers, defined as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. Specific elements of the Staff Proposal related to decisions in this order are summarized in the Discussion section, below.

NOTICE OF PROPOSED RULEMAKING

On October 28, 2016, the Secretary issued a "Notice Soliciting Comments on Staff Proposal," which sought initial comments by December 5, 2016, and reply comments by December 19, 2016. Further, pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) was published in the State Register on November 2, 2016 [SAPA No. 15-E-0751SP1]. The time for submission of comments pursuant to the SAPA Notice expired on December 19, 2016. In addition, a technical conference was held on November 28, 2016. Input was also solicited on process and areas of focus for Phase Two and a number of comments were received by December 23, 2016. Various initial and reply comments on the Staff Proposal were received, including thousands of comments from members of the public, as summarized in Appendix D and addressed below in where relevant. The first section of Appendix D contains short names for commenters; those names are used throughout this order to refer to the commenters.

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 the 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 E. 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.

SUMMARY OF DECISIONS

The Discussion Section offers a full explanation of the Commission's decisions in this order, including the reasons that recommendations from the Staff Proposal and from stakeholder comments are adopted, modified, or rejected. To ensure that the Commission's decisions are clearly identified for the benefit of Staff, active parties and interested stakeholders, the major decisions are summarized in this section.

This order directs an immediate transition from NEM to a VDER Phase One tariff. Projects interconnected prior to the date of this order will retain NEM compensation unless and until their owners opt-in to the VDER Phase One tariff. The VDER Phase One tariff includes two components: Phase One NEM and the Value Stack tariff. Mass market projects interconnected before January 1, 2020, subject to further limitations described below, will be compensated based on Phase One NEM. RNM, large on-site, and CDG projects for which, within 90 business days of this order, 25% of interconnection costs have been paid or a Standard Interconnection Contract has been executed if no such payment is required will be compensated based on Phase One NEM, with CDG subject to further limitations described below. RNM, large on-site, and CDG projects that do not qualify for Phase One NEM will be compensated based on the Value Stack tariff.

A. Transition from NEM to Phase One NEM

To effectuate an immediate transition away from NEM, NEM compensation under PSL §66-j will no longer be available to new projects after the date of this order. Projects that either are in service or that have completed Step 8 of the Standard Interconnection Requirements (SIR) for projects larger than 50 kW or Step 4 of the SIR for projects smaller than 50 kW by the close of business on March 9, 2017 will receive NEM based on existing

tariffs; all other projects will receive service based on the VDER Phase One tariff. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017. New wind projects will be eligible to receive NEM pursuant to PSL §66-1 until the caps described in that statute are reached, and will then be transitioned onto the then-applicable compensation mechanism. Projects compensated under NEM will be able to opt-in to the Phase One Value Stack tariff.

B. Phase One NEM

Phase One NEM will be available to projects that interconnect or make a defined financial commitment within 90 business days of this order. CDG projects eligible for Phase One NEM are further subject to the availability of by-utility MW capacity allocations, summarized below. New mass market, on-site projects will be eligible for Phase One NEM until the earlier of January 1, 2020 or a subsequent Commission order addressing such projects in this proceeding. The deployment of mass market projects under Phase One NEM will be monitored to ensure that these projects do not create the potential for unreasonable impacts on non-participants based upon a MW capacity allocation for each utility that provides for continued opportunity under the VDER Phase One tariff. Utilities will provide frequent and transparent reporting on the progress under the MW capacity allocation and will provide notice upon hitting 85% of the allocation amount so that the Commission may consider what action is appropriate.

Phase One NEM is identical to NEM, except that projects eligible for Phase One NEM will be subject to a

compensation term length of 20-years from their in-service date and will have the ability to carry-over excess credits to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects compensated under Phase One NEM will be able to opt-in to the Phase One Value Stack tariff. Projects, other than mass market on-site projects, compensated under Phase One NEM must be equipped with utility metering capable of recording net hourly consumption and injection.

C. The Value Stack

Under Phase One, the Value Stack tariff will only be available for technologies and projects that are eligible for NEM; other DER technologies will be addressed in subsequent Phases. The Value Stack tariff shall be based on monetary crediting for net hourly injections. Excess credits will be eligible for carry-over to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects eligible for the Value Stack tariff will receive compensation for a term of 25-years from their in-service date. Projects under the Value Stack tariff must be equipped with utility metering capable of recording net hourly consumption and injection.

Compensation under the Value Stack for net hourly injections will be calculated based on the value associated with: 1) Energy Value, based on the Day Ahead hourly zonal locational-based marginal price (LBMP), inclusive of losses; 2) Capacity Value, based on retail capacity rates for intermittent technologies and the capacity tag approach for dispatchable technologies based on performance during the peak hour in the previous year; 3) Environmental Value, based on the higher of the latest CES Tier 1 Renewable Energy Certificate (REC) procurement price published by NYSERDA or the Social Cost of

Carbon (SCC); and 4) Demand Reduction Value (DRV) and Locational System Relief Value (LSRV), based on a deaveraging of utility marginal cost of service (MCOS) studies, performance during the 10 peak hours, and further process as detailed in the Discussion Section. In addition, utilities are directed to develop options for a fee-based portfolio service under which DG projects can be aggregated into a virtual generation resource.

CDG projects compensated under the Value Stack tariff will be eligible for an MTC, equal to the difference between the "Base Retail Rate" and "Estimated Value Stack" as detailed below in the Discussion Section. CDG projects will receive a pro-rata MTC based on the portion of their project that is dedicated to serving small customers and shall not receive a DRV for that portion of their project. Eligibility for MTC compensation will be subject to the availability of MW capacity allocations in each utility that are derived from the incremental 2% net revenue impact limitation, summarized below.

MW capacity is further allocated to three distinct Tranche buckets as follows: Tranche 0 (Phase One NEM)/Tranche 1 (Value Stack plus MTC equal to 100% Base Retail Rate); Tranche 2 (Value Stack plus MTC equal to 95% Base Retail Rate); Tranche 3 (Value Stack plus MTC equal to 90% Base Retail Rate). The specific method and allocations to distinct Tranches is further detailed below under the Discussion Section and in Table 2. After 90 business days from the date of this order, any remaining capacity in Tranche 0 shall be rolled over to Tranche 1. Utilities will provide frequent and transparent reporting on the progress of Tranches and will provide notice upon hitting 85% of the total allocation amount so that the Commission may consider what action is appropriate. Eligibility for placement in a Tranche will be based on the time-stamp of a 25% advanced payment for interconnection upgrade costs or execution of a

Standard Interconnection Contract if no such payment is required.

D. Managing Potential Impacts on Non-Participants

To manage the potential impacts of the VDER Phase One tariff on non-participants, an incremental net annual revenue impact of approximately 2% for each utility will be established for all projects interconnected after the date of this order. The 2% upper bound will not result in a hard cap, but instead is used to design capacity-based allocations for mass market and CDG projects.

E. Cost Allocation Principles

Costs associated with compensation under the VDER Phase One tariff will be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER. For compensation that does not reflect a value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries.

F. Inclusion of Energy Storage

A Project that include energy storage paired with an eligible resource will be eligible for compensation under NEM, for mass market on-site projects, or the VDER Phase One tariff. As part of the development of the final Value Stack tariff, Staff will consider whether there are alternatives to their recommendation to base compensation on net monthly injections in order to better reflect actual storage configurations and value while still avoiding uneconomic arbitrage. The application of the Phase One tariff to stand-alone storage facilities will be addressed in subsequent phases.

G. Mitigation of Bill Impact and CDG Project Costs

Staff is 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 include: development costs, consolidated billing, customer maintenance costs, and interconnection costs.

H. Enabling Participation of Low-Income Customers in VDER Programs and Tariffs

The Commission directs Staff to work with utilities and interested stakeholders to consider an interzonal CDG credit program designed to provide benefits from CDG projects interconnected in service territories and load zones other than that of the low-income participant. The Commission also supports NYSERDA's continued investigation into enabling low-income customer participation in CDG projects, and directs NYSERDA to file CEF investment chapters to support programs aimed to encourage and incentivize low-income participation in CDG projects. Finally, the Commission directs Staff to consider options to encourage low-income participation in CDG under the VDER Phase tariffs, including tailored approaches for CDG projects that comprise a majority of low-income off-takers.

I. Oversight of DER Providers

Given the advancement of this and other proceedings since the filing of the initial DER Oversight Staff Proposal on July 28, 2015, the Commission directs Staff to develop an updated whitepaper that will be issued for public comment within thirty days such that the Commission will be able to consider the DER oversight provisions at the same time as it acts on the implementation issues in this proceeding.

J. Further Process

To enable the full implementation of the Value Stack tariff, the utilities are directed to make specific filings,

following engagement with Staff and stakeholders, to enable public comment and Staff consideration such that the Commission may consider a Value Stack Implementation order as soon as Summer 2017. While a full listing of items appears in the Discussion Section, particular items of note include filing by each utility of: tariff leaves for implementing Phase One NEM; proposed implementation of cost allocation principles; proposed method and values for capacity; the most recent MCOS studies and workpapers followed by specific DRVs and LSRVs along with identification of specific locations and MW caps for LSRVs; MTC values; and a work plan and timeline for developing locationally granular prices to reflect the value to a utility's distribution system from DER additions.

K. Commencement of VDER Phase Two

Phase Two will commence in May 2017 with a procedural conference or other meeting of interested parties. An agenda will be issued at least five days in advance of the meeting. Specific topics to be addressed and prioritized in Phase Two are discussed further under the Discussion Section of this order.

DISCUSSION

I. THE NEED FOR TRANSITION

Through the REV initiative, the Commission has taken concrete steps to transform New York's electric grid into a modern, distributed, integrated, transactive, and increasingly clean system. This order addresses a fundamental requirement of building a distributed grid and offering fair and accurate compensation to all market participants: compensation of DER for the values they create. The REV initiative, through which the Commission is pursuing a consumer-centric, economically efficient, and environmentally sustainable energy future, demands accurate valuation of and compensation for DER. REV's

premise that clean energy deployed at scale will lead to increased consumer and third party engagement requires more precise price signals for DER products and services.

DER is a broad term that includes a range of technologies designed to interact with and affect the grid from the grid edge, generally from behind a utility meter, including DG, energy efficiency (EE) technologies, and demand response (DR) and reduction projects. Individual DER products and services number in the thousands, and more are developed all the time, but common examples include solar panels, energy storage, smart appliances, and learning thermostats.

In this diverse and growing marketplace, a compensation system must be value-based, rather than technology-based. Each DER will create different values for the electric system, and impose different costs on the electric system, depending on its individual characteristics and the nature of its use, including when and where the DER is operated. The values and services offered by DER are wide-ranging and will continue to be discovered and developed over time, but today include: reduced energy consumption, energy generation, green energy attributes representing reduction in emissions of greenhouse gasses and other pollutants, capacity, reduced system stress, displacement of the need for traditional grid infrastructure, increased reliability, load shifting, demand response, peak load reduction, voltage support, frequency management, and reactive power.

To achieve the energy future envisioned by REV, we must develop and implement mechanisms that identify these and other values and offer appropriate compensation. In order to incentivize customers and DER providers to install and operate DER in a manner that maximizes the benefits for themselves, the integrated electric system, and society as a whole, compensation

must accurately reflect the values created at a granular level. This requires the replacement of legacy compensation systems that do not and cannot accurately reflect these values, such as NEM. As a compensation mechanism, NEM is easy to understand and implement and, coupled with other incentive programs, proved an important and effective means to nurture the growth of New York's DG industry, particularly solar photovoltaic (PV) generation. However, especially when coupled with traditional volumetric rate structures, NEM does not provide sufficient information to serve as a basis of efficient investment decisions or to identify and compensate for the values that can be provided to the system. For most customers compensated under NEM, compensation reflects only the amount of energy generated and the customer's existing rate, and has little or no relationship to the actual values provided to or costs imposed on the system. For any individual DER, NEM may be over- or under-compensatory as compared to the actual values and costs that resource creates. Furthermore, to the extent that a failure to offer proper compensation by recognizing values leads to the installation of DER that creates lower benefits or greater costs for the electric system than would otherwise be the case, all utility customers, and in particular non-participants, suffer the impacts of those greater costs and lower benefits.

At relatively low levels of penetration, the inefficiencies of NEM could be tolerated. However, as both customer interest in and New York's need for clean and distributed generation increases, driven by initiatives including the CES and CDG, it has become increasingly vital for compensation and incentives to sufficiently encourage the deployment of DG and its location, design, and operation in a manner that maximizes values to the customer, the electric

system, and society. The continued success of New York's DG industry requires more efficient pricing mechanisms, without which the growth of these DER will be inhibited. While the market structure, products, and transactional mechanisms will evolve over time, a transition to a more precise mechanism to value and compensate DER must begin now in order to take full advantage of the opportunities.

The Staff Proposal, as informed by extensive collaborative work involving a multitude of stakeholders, offers a framework for compensation of NEM-eligible DER appropriately based on the values those DER create for the electric system, the Value Stack framework. Implementation of that framework will offer improved price signals for DER development while also ensuring the continued health of the DER market and managing potential impacts on non-participants. The extensive comments submitted on the Staff Proposal, fully summarized in Appendix D, offer general support for this framework and for many of the Proposal's elements, while also suggesting several modifications and arguing that various elements require further development. We agree that some modifications to the Staff Proposal are warranted and that, as discussed herein, some aspects of the methodology require further limited inquiry prior to full implementation of the Value Stack tariff. However, we believe that this further inquiry can be accomplished during the next several months, so that the Commission can consider a final implementation proposal, with stakeholder participation and commentary, as soon as Summer 2017. By adopting foundational policy decisions for a VDER Phase One tariff and its related elements in this order, including decisions regarding the Value Stack, we can offer clarity to DER customers and developers and identify what steps must be taken to finalize the Value Stack under Phase One.

Because we find that continuation of NEM is inconsistent with REV, Commission policy, and the public interest, we direct an immediate transition away from NEM to a new VDER Phase One tariff. To ensure that development activities can continue during the interim period while the Value Stack is finalized, the VDER Phase One tariff will include a new category of DER compensation, referred to as Phase One NEM, which offers equivalent compensation to NEM but manages NEM's imperfect incentives and impact on non-participants by including a limited term and limits on how many MWs of generation can be developed at this compensation level.

The following discussion begins with an explanation of the reasons for and the mechanisms required for transition from NEM to the first stage of the VDER Phase One tariff, Phase One NEM. The next section describes generally applicable policy decisions regarding the VDER Phase One tariff. Next, the order identifies the framework for Value Stack tariffs and describes the process for finalizing and implementing those tariffs. Finally, the order sets forth a roadmap for moving to the next stage of development in valuation and compensation of DER, both through VDER Phase Two and through work in related proceedings.

II. TRANSITION FROM NEM TO VDER PHASE ONE

A. Transition Away from NEM

1. Staff Proposal

The Staff Proposal recommends that projects in-service at the time of this order continue to receive compensation under existing NEM rules until 20 years from their in-service date. It proposes that new projects put into service after the order be compensated based on a new methodology, with limited exceptions.

Staff recommends that mass market and small wind projects interconnected prior to January 1, 2020 continue to

receive NEM compensation until 20 years from their in-service date. Staff recommends that RNM projects that qualify for monetary crediting pursuant to the Transition Plan Order⁹ receive NEM compensation based on the terms of that Order until 25 years from their in-service date. In addition, Staff recommends that continued NEM compensation, for 20 years from in-service date, be available to a certain segment of projects put into service after the order subject to both a deadline and a capacity limit.

2. Comments

Many parties submitted comments discussing the proposed transition away from NEM as a compensation mechanism. Several parties, including Solar Parties, NYSEIA, CCSA, EDF/Policy Integrity, NRDC, Acadia, and Pace, emphasize the important role NEM has played in developing the solar industry but acknowledge the impetus for change and generally support Staff's proposed framework for a transition, subject to certain recommended modifications to elements of the new compensation framework and a transition that is gradual and predictable in nature. A number of parties, including AEEI, ACE-NY, NCEC, NY-BEST, and Bloom Energy, offer strong support for an expeditious transition away from NEM to a more accurate compensation methodology, as proposed by Staff. JU, IBEW, UIU, PULP, MI, and Nucor express concern that a failure to quickly transition away from NEM could lead to substantial impacts on ratepayers as the penetration levels of solar and other NEM-eligible technologies grow.

⁹ Cases 14-E-0151 et al., Hudson Valley Clean Energy, Inc. - Petition for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings (issued April 17, 2015) (Transition Plan Order).

Some parties, including EDA, NYCEJA/NYLPI, and several small solar developers express concern that transition away from NEM is premature. Over 700 individual comments were received supporting continuation of NEM, which they argue is one of the most basic foundations of renewable energy policy and energy democracy. Over 2,200 individual comments were received urging the Commission to reject proposed plans to impose caps on NEM and to set a goal of 100% renewable energy by 2035. In particular, commenters argue that NEM supports the expansion of residential clean energy and that New York State needs additional clean, distributed energy, not less.

3. Determination

NEM was instituted by statute, subject to a rated generating capacity ceiling in each utility territory equal to one percent of the 2005 electric demand for each utility, respectively.¹⁰ However, the Commission was authorized to increase these ceilings as deemed necessary in the public interest. Consistent with this authority, the Commission raised those caps, as described above, through findings that permitting additional NEM would be in the public interest.

Since the Commission's decision to raise the caps to 6%, and subsequent adoption of temporary floating caps, circumstances have changed. First, progress in the REV proceeding has demonstrated that smarter planning, including the optimization of DER and their associated values, is both possible and necessary. Second, it is now clear that volumetric crediting, on which NEM is based, fails to reflect the full and accurate value that DER provide to the grid. Third, significant interest in the Commission's CDG policy is dramatically

¹⁰ PSL §66-j(3)(a)(iii). NEM for wind generation projects has a separate rate generating capacity ceiling of 0.3% of the 2005 electric demand for each utility, respectively. PSL §66-l.

accelerating the level of DER that will be integrated on the system, such that associated costs to non-participants could significantly increase if prompt action is not taken to more accurately compensate these resources and fairly allocate the costs. When the Commission adopted the CDG policy, we noted the need to promptly develop a more accurate compensation method for these resources.

Based on these changed circumstances, further interconnection of projects under NEM is not in the public interest. Even applying a conservative estimate of projects in the current interconnection queue that will come to fruition, it is evident that continued application of floating NEM caps could result in substantial impacts for non-participant customers and a missed opportunity to incentivize those resources that will provide the most value to the system. A return to a 6% rated generating capacity ceiling, with a hard cut-off at that ceiling, would be inequitable, creating a sharp drop in compensation for customers interconnected once that ceiling was reached, and could limit our ability to create a transitional period while managing impact on non-participants. Limiting NEM at its current penetration level in each utility, while offering certain categories of projects, including those in advanced stages of development, the opportunity to receive equivalent compensation based on similar terms through Phase One NEM, will allow for a rational transition that balances the interests of participating and non-participating customers. Such a limit is also consistent with the intent expressed in the Interim Ceiling Order, which explained that the floating ceilings would be set at the level of penetration at the time of the implementation of a more accurate methodology.¹¹

¹¹ Case 14-E-0151, supra, Interim Ceilings Order.

We appreciate that NEM has served as an important mechanism to develop the solar market in New York and that it forms an important part of the business model of many developers. However, as even many of those developers and clean energy advocates recognize in their comments, progress beyond NEM is necessary to encourage development of DER consistent with REV goals while ensuring equity to all ratepayers. The purpose of this order is not to slow or limit the deployment of clean, distributed resources; rather, this order is necessary to drive achievement of New York's aggressive clean energy goals while also creating the grid of the future envisioned by REV. Those clean energy goals were established based on the State Energy Plan, and any recommendations to modify them or add further goals should be brought to that forum.

For the above reasons, NEM compensation under PSL §66-j will no longer be available to new projects after the date of this order. Projects that either are in service or that have completed Step 8 of the SIR for projects larger than 50 kW or Step 4 of the SIR for projects smaller than 50 kW by the close of business on March 9, 2017 will receive NEM based on existing tariffs; all other projects will receive service based on the VDER Phase One tariff. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017. This will ensure that projects for which all development activity is complete will retain their expected compensation mechanism. Relying on the SIR milestones is appropriate because they provide clearly defined stages and will

avoid the potential for numerous factual disputes on projects' statuses.

As a replacement for NEM prior to the implementation of the Value Stack, the Commission adopts a mechanism called Phase One NEM that is identical to NEM, except that it is subject to a limited term length for each project. Phase One NEM will be available for projects interconnected after March 9, 2017 that either interconnect or make a defined financial commitment within 90 business days of this order, subject to defined limits consistent with the below discussion regarding impact on non-participants.

In addition, new mass market, on-site projects, as defined below, will continue to be eligible for Phase One NEM until the earlier of January 1, 2020 or a Commission order addressing such projects in this proceeding. Eligible new wind projects will receive NEM pursuant to PSL §66-1 until the caps described in that statute are reached, and will then be transitioned onto the then-applicable compensation mechanism.

To implement this approach, each of the utilities will be required to record the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017 and to file with the Secretary within seven days a preliminary letter stating that MW number. Each of the utilities must file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory. As projects served under PSL §66-j are taken out of service, the ceilings shall automatically decrease

to match the capacity of projects remaining in service. These decreasing ceilings should not be used to prevent customers served under PSL §66-j from repairing their system. Furthermore, the ceilings will not decrease below the 1% of 2005 electric demand level specified in PSL §66-j.

Projects not eligible for NEM compensation will be served under and compensated based on Phase One NEM or a subsequent tariff, as discussed below.

B. Managing Potential Impacts on Non-Participants

1. Staff Proposal

The Staff Proposal explains that both NEM and VDER Phase One tariffs are expected to result in net revenue impacts to utilities, which will be reflected on customer bills. The Staff Proposal includes a detailed, if preliminary, analysis of the potential net revenue impacts based on the identifiable and calculable values created for utilities by DER as compared to the costs imposed by compensating customers under NEM and through Staff's proposed Value Stack tariff. While the Proposal recognizes that the ongoing transition via REV towards more precise identification and quantification of value places certain limitations upon this analysis, Staff maintains that the analysis offers a useful tool for assessing the potential impacts of a VDER Phase One tariff on non-participating customers and that it is sufficiently informative to use as a guide in managing those impacts under Phase One.

The analysis estimated an incremental amount, based on revenue requirements embedded in existing rates, which would need to be collected from all customers as a result of the compensation methodologies proposed. Due to the highly speculative nature of predicting future rate levels and rate design changes, Staff adopted a simplified approach employing a snapshot of existing tariff levels, historical commodity prices,

and customer class structures and revenues. The analysis focused upon several DER deployment and compensation scenarios.

The Staff Proposal explains that while Phase One will have a meaningful impact on DER deployment and make positive steps towards more precise value of DER, the impacts will ultimately be bounded by the anticipated two-year period for application of the VDER Phase One tariff before moving to development and implementation of subsequent phases. To balance market opportunity and revenue impact during Phase One, the Staff proposal suggests, and bases its analysis on, a maximum incremental net annual revenue impact of 2% for each utility's residential customer class, inclusive of bundled and delivery-only customers, for all projects interconnected under the VDER Phase One tariff. The Staff Proposal explains that an incremental 2% impact reasonably balances the need for an upper boundary impact on non-participating customers while also establishing room for market growth in all utility service territories. The analysis focused upon technologies and project types that represent the vast majority of current market potential, as well as the largest potential net revenue impact (i.e., primarily solar CDG projects, as well as mass market on-site projects).

2. Comments

Commenters have divergent views and perspectives on Staff's approach and recommendations to balance cost impact with market opportunity. Solar Parties, CCSA, Acadia, NRDC, NYSEIA and CCR argue that a 4% net revenue impact is more appropriate in order to provide a more gradual transition from NEM as well as to provide sufficient opportunity for market participation and time for the market to mature. Many of the same commenters also posit that 4% is also more appropriate given that the Value Stack remains incomplete and imprecise, contributing to

uncertainty in calculation of an accurate net revenue impact. AEEI expresses concern about the approach used to calculate the net revenue impact, but nonetheless comments that a 3% bounding would be more appropriate for many of the same reasons articulated by Solar Parties. SolarCity supports a bounding on impact, but comments that utility-specific limits and revenue impact mitigation measures are more appropriately considered within the context of utility rate cases. Solar Parties point out that the net revenue impact estimate does not represent lost revenue for the utility since any differences in approved revenue requirement and actual revenues collected would be recovered through either a decoupling rider or an increase in base rates. Pace believes that there has not been sufficient basis established in the record for claiming detrimental impact on non-participants, and therefore argues that the 2% net revenue impact is inappropriate now. EDA similarly comments that there should not be any limitation on the program.

JU supports the spirit and principle of limiting impacts to Staff's recommended 2%, but disagree with the approach Staff has taken to calculate the precise impact. Instead, the utilities propose calculating the 2% target as the product of the three-year average of SC1 annual delivered kWh levels multiplied by the per kWh rates for delivery and three-year average of commodity rate. Further, JU claims that the approach would result in a customer bill increase of as much as 25% in some service territories, or \$494 million statewide each year. JU is also concerned that Staff recommends that the 2% only apply to new projects instead of also including systems that are already interconnected. MI, PULP, and UIU also express concern that Staff's recommendation is only focused on incremental impact. Solar Parties respond to JU in reply comments stating that their approach to calculating net revenue

impact understates residential revenues, overstates impacts from mass-market PV exports, and does not account for any upward adjustment in DER value associated with future identification and quantification of DER benefits. TASC concurs that JU overstates impacts from mass-market PV exports.

MI expresses concern that Staff's 2% approach applies to total annual revenues as opposed to utility delivery revenues only, which MI argues would be more appropriate in this context. MI is also concerned about the context in which the 2% figure was selected and whether the full scope of other Commission-approved programs and initiatives that impose costs on customers were taken into consideration. PULP is similarly concerned and offers their assessment of aggregate impacts. Nucor is likewise concerned that the 2% net revenue impact bounding will not limit excessive cost shifts and recommends suspending any cost shifting elements of Staff's proposal upon hitting any cost impact boundary. UIU expresses concern that assessment of cost and benefits of DER has not been aided by a sufficiently detailed analysis and recommends imposing a hard cap on mass market projects and erring on the side of being conservative in calculating the 2%. PULP objects to the approach to set an artificial level of additional ratepayer support to justify the recommendations for subsidies to DER providers, and comments that the Staff Proposal fails to consider the cumulative effect of ratepayer increases already approved by the Commission or embedded in rate cases and other REV related proceedings.

3. Determination

Both NEM and the VDER Phase One tariff adopted in this order impact customer bills. NEM compensation results in reduced utility revenues and surcharge collections, which in some cases exceed the value of the benefits provided to the utilities by those projects. Because the utilities are

required, through revenue decoupling mechanisms, to bill customers at rates that result in net revenue equal to the approved annual delivery revenue requirement, any net revenue impact will be directly passed on to customers, with non-participating customers bearing the brunt of the impact since participating customers have offset much of their usage. Similarly, because most surcharges are designed to collect fixed total amounts based on Commission direction, reduced surcharge collections from NEM customers result directly in increased surcharge collections from non-participating customers.

Thus, the purpose of limiting the net revenue impact is not to protect overall utility revenues but instead to protect ratepayers, particularly non-participants, who are directly impacted as a result of revenue decoupling mechanisms and surcharge collections. Revenue decoupling mechanisms have been supported by environmental organizations and DER advocates as a method of ensuring that utilities are partners in, rather than opponents of, DER deployment and energy conservation. A significant portion of surcharge collections go to programs that support DER deployment. Phase One NEM compensation results in the same potential impacts as traditional NEM compensation, subject to a limited duration. While the Value Stack methodology manages and reduces these impacts, projects compensated under the Value Stack tariff that receive an MTC will still result in some net revenue impact.

The Commission is very aware of the compounding effect of bill impacts from various rate cases and initiatives approved by the Commission over the last several years as identified by PULP and expressed as a concern by UIU and MI. We note that while the list in PULP's comment appears long, the impacts of the items on the list are not all cumulative since many of the rate cases impact different geographic areas of the state.

While approval of a rate case or initiative has an immediate impact of a customer bill increase, the Commission balances those decisions with the underlying customer benefits to be produced. For example, rate case decisions are most often driven by the need to replace aging infrastructure, build new systems to meet increased demands, and adopt the latest technologies, all of which will benefit customers for many years to come. Similarly, the CES will attract billions of dollars in private investment for new renewable power, develop new jobs and new green choices for consumers, reduce carbon and other harmful pollutants, and allow New York to continue to maintain a diverse and reliable energy supply.

While, as the Staff Proposal acknowledges and several commenters maintain, some uncertainty exists in the precise calculation of the impacts of NEM and the potential impacts of the Value Stack, failing to address those impacts with as much precision as possible would represent an abdication of the Commission's responsibility to ensure just and reasonable rates for all customers. To mitigate impacts on non-participants during Phase One, both the availability of Phase One NEM and the inclusion of an MTC for certain projects in the Value Stack tariff will be designed with limits based on potential net revenue impacts. In calculating these net revenue impacts, we will consider all identifiable and calculable system values created by DER, including locational values and environmental values.

With those considerations, as well as other recent bill impacts and benefits, in mind, the Commission adopts Staff's recommendation of an upper bound for incremental net annual revenue impact of approximately 2% for all projects interconnected after the date of this order under the VDER Phase One tariff. The 2% upper bound will not result in a hard cap on

DER installation but instead, as described below, is used to design capacity-based allocations to limit the projected net revenue impact of mass-market and CDG projects under Phase One NEM and CDG projects under the Value Stack both through automatic transitions in CDG Tranches and through circuit breakers/triggers that inform the Commission that further action may be warranted.

Based on Staff's estimate of capacity-based allocations that can be accommodated under a 2% upper bound, this level reasonably balances the potential rate impacts with the need to provide market opportunity, and also takes into account the currently non-monetized benefits that these systems provide. The 2% level also ensures that there will be meaningful opportunities for customers in each utility service territory to install and invest in DER or participate in a CDG project. This order, coupled with the one billion dollar NY-Sun initiative, support for solar and other DG financing through the New York Green Bank, and other DG programs in the CEF, continues the Commission's support for aggressive DER deployment, while mitigating the potential bill impacts that would result from continued NEM and ensuring that continued DER development will, consistent with the goals of REV, take system needs into account and be compensated where it addresses those needs.

JU is correct that the approach proposed by Staff for calculating 2% in its Proposal was flawed. Because the calculation of 2% would vary each month based on commodity and other rate variations, the basic method proposed by JU is superior.¹² However, the list of rate elements proposed by JU excluded certain material elements. Because these elements vary

¹² Put simply, the JU approach is to multiply the average annual kWh for SC1 in each territory by a dollar per kWh rate to get a pro forma revenue estimate that is then multiplied by 2%.

from month to month, the JU approach of using three year averages is sensible.

With respect to the Phase One incremental CDG MW allocation, we also are persuaded by some of JU's comments. The 2% customer bill impact constraint is a useful target. However, the incremental CDG MW allocation should be defined by a number of MWs upfront, based on the percent of peak load that approximates such an impact. However, where JU proposes that the MW-based "cap" be set as a uniform 5% of each utility's peak load, we feel these two metrics could better be balanced. By relying on the estimated MTCs discussed below, we find that the total number of incremental CDG MWs allocated to the Tranche system in Phase One shall be approximately equal to 4% of forecasted 2016 peak load for Consolidated Edison and Orange & Rockland. The total number of incremental CDG MWs allocated to the Tranche system in Phase One for Central Hudson, National Grid, New York State Electric and Gas, and Rochester Gas and Electric shall be approximately equal to 7% of forecasted 2016 peak load.

This conclusion was based on the following volumetric rate elements and calculation methods:

- A. SC1 Tariffed Volumetric Delivery Rates per kWh. Calculated as the volumetric delivery rate element that is effective on the date of this order.
- B. SBC Rates per kWh. Calculated as the weighted average per kWh SBC rate for the 36 months in the years 2014, 2015, and 2016. The weights used for calculating this average are the monthly kWh delivered to SC1 customers in the same months in 2014, 2015, and 2016.
- C. MFC Rates per kWh. Calculated as in B.
- D. Commodity Rates per kWh. Calculated as in B.
- E. Calculating the 2% target for each utility. To derive total annual SC1 revenue estimates, the sum of these per kWh Rate elements are multiplied

by the average annual kWh delivered to SC1 customers, provided by JU with its comments. These averages are then multiplied by 2% to derive the target each utility.

- F. The number of MWs of continuing onsite NEM growth, and the related revenue impacts, is estimated for the Phase One period and subtracted from the above 2% total. (Table 1)
- G. The estimated remaining revenues are divided by the estimated revenue impact per MW of CDG to determine the approximate number of incremental CDG MWs consistent with the 2% target.
- H. These MW estimates are compared to each utility's peak 2016 load as estimated by the NYISO, and a %-of-peak rule is set for each utility. (Table 2)

The number of MWs shown in the bottom row of Table 2 are the incremental CDG MWs for each utility.

TABLE 1. CALCULATING 2% REVENUE IMPACT, AND ALLOCATING TO CONTINUING ONSITE AND CDG

	<u>CHGE</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>ConEd</u>	<u>RGE</u>
SC1 Load Weighted Rate	\$0.1452	\$0.1797	\$0.1156	\$0.1058	\$0.2038	\$0.1060
SC1 kWh/yr (3 yr avg)	2,070,088,000	1,578,881,333	11,340,042,826	4,871,585,653	13,849,333,333	2,597,630,513
Rate x kWh	\$300,479,547	\$283,738,460	\$1,310,994,991	\$515,208,388	\$2,822,430,784	\$275,242,570
x 2%	\$6,009,591	\$5,674,769	\$26,219,900	\$10,304,168	\$56,448,616	\$5,504,851
Continuing Onsite NEM						
kWh/MW	1,156,320	1,235,160	1,314,000	1,336,776	1,235,160	1,336,776
x 0.5	578,160	617,580	657,000	668,388	617,580	668,388
\$ shift/kwh	\$0.0737	\$0.0942	\$0.0457	\$0.0470	\$0.0919	\$0.0487
\$ shift/MW	\$42,592	\$58,177	\$30,047	\$31,427	\$56,755	\$32,532
MWs	30	25	100	20	90	5
\$ for continuing onsite	\$1,277,756	\$1,454,425	\$3,004,666	\$628,541	\$5,107,973	\$162,662
Remainder for CDG	\$4,731,835	\$4,220,344	\$23,215,234	\$9,675,626	\$51,340,642	\$5,342,189
kWh/MW	1,271,848	1,358,128	1,444,159	1,472,145	1,357,414	1,473,426
\$ shift/kwh	\$0.0494	\$0.0700	\$0.0215	\$0.0228	\$0.0677	\$0.0244
\$ shift/MW	\$62,865	\$95,017	\$31,039	\$33,534	\$91,842	\$36,000
CDG MWs @ 100% NEM and no Tranche 0 REC retirements	75	44	748	289	559	148

TABLE 2. BALANCING 2% REVENUE IMPACT WITH % OF PEAK "RULE"						
	<u>Central Hudson</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>ConEd</u>	<u>RGE</u>
2016 peak MWs	1,104	1,164	6,776	3,192	13,705	1,591
% of Peak						
4%	44	47	271	128	548	64
7%	77	81	474	223	959	111
CDG MWs Assuming: --2% bill impact (net of new rooftop) --100% NEM and no Tranche 0 REC retirements	75	44	748	289	559	148
INCREMENTAL CDG MWs	77	47	474	223	548	111

C. Limited Availability of Phase One NEM

The compensation available in Phase One NEM is equivalent to the compensation provided by NEM and will be offered according to the same rules, except that projects will only be eligible to receive Phase One NEM for a term of 20 years from the date of interconnection, as further discussed and explained in the section regarding compensation term lengths below.¹³ Customers will be eligible for Phase One NEM where their DER project: (a) meets the eligibility rules for NEM; (b) is interconnected on or after March 10, 2017; (c) has a payment made for 25% of its interconnection costs,¹⁴ or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order;¹⁵ and (d) for CDG projects, has a payment made for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, before the capacity limit for CDG projects under Phase One NEM is reached, which is established by this order for each interconnecting utility. In addition, all mass market, on-site DER projects will be eligible to receive Phase One NEM if those projects meet the eligibility rules for NEM and are interconnected before the earlier of January 1, 2020 or a subsequent Commission order. As described below, to manage potential impacts on non-participants, a capacity allocation has been established for

¹³ Remote net metered projects eligible for monetary crediting grandfathering as established in the Transition Plan Order will receive Phase One NEM for a term of 25 years, consistent with that Order.

¹⁴ A payment of 25% interconnection costs is a step established in the SIR and constitutes a sufficient level of financial investment to demonstrate that the project is advancing through the development process.

¹⁵ As this order is dated March 9, 2017, this deadline will fall on July 17, 2017.

mass market Phase One NEM projects so that the Commission will receive notice and consider appropriate action if the number of mass market projects interconnected exceeds expected levels.

Phase One NEM is established to ensure that a compensation mechanism exists for projects interconnected after the date of this order and prior to the finalization of the Value Stack under Phase One to encourage continued market and development activity during that period. As discussed below, due to the maturity of the mass market and the fact that many mass market customers currently do not yet have sufficiently advanced metering for application of the Value Stack tariff, Phase One NEM will be available for mass market projects through January 1, 2020. While Phase One NEM continues the imperfect incentives created by NEM, it includes limitations to manage negative impacts. A fixed term of compensation is required to offer customers and developers the certainty they need to make investments, but must be limited in recognition of the imperfections of the current NEM compensation mechanism.

The eligibility rules for CDG under Phase One NEM, including the requirement of payment of a substantial portion of interconnection costs within a fixed period and the imposition of a rated generating capacity cap for each utility, will ensure that potential impacts on non-participating customers are properly managed. This approach will also ensure that Phase One NEM is only offered to CDG projects that have sufficiently advanced through the development process, while projects earlier in that process will be compensated based on the more accurate Value Stack tariff. The fixed period of 90 business days for payment of interconnection costs is consistent with the timeframes established in the SIR queue management process to ensure that only more mature projects that continue to advance through the necessary stages and meet all necessary financial

commitments are included. The capacity limits are established based on potential impacts on non-participating customers and are applied only to CDG projects. This is appropriate given that RNM and large on-site projects that are compensated based on volumetric crediting do not impose significant costs on non-participating customers under the current NEM construct, since those project types receive compensation for energy injected into the utility system based only on the commodity value of that energy.¹⁶ Once the 90 business day period has passed or - for a CDG project - after the relevant capacity cap is reached, if a customer makes a payment for 25% of a project's interconnection costs or, if no such payment is required, executes a Standard Interconnection Contract, that customer will be compensated based on the Value Stack tariff, once that tariff has been implemented.

D. Transition from Phase One NEM to Implementation of Value Stack Tariff

In addition to making foundational policy decisions launching the transition towards more accurate valuation and compensation, this order begins the process of defining the Value Stack tariff and its components, while recognizing that further process is necessary before the tariffs can be implemented. The Commission is confident that, with the direction offered in this order, Staff and interested stakeholders can sufficiently develop the record for a

¹⁶ As discussed in the Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures, issued December 15, 2014 in Cases 14-E-0151 et al., RNM projects compensated based on monetary crediting may impose such costs; however, because grandfathering rules for those projects have already been established in the Transition Plan Order and customers have made investments in reliance on that Order, the eligibility of those projects for NEM-based compensation will not be modified here.

Commission decision finalizing and implementing the VDER Phase One tariffs as soon as Summer 2017. For that reason, the Phase One NEM CDG caps are designed to allow continued project development between the issuance of this order and Summer 2017.

III. FOUNDATIONAL POLICIES FOR NEM TRANSITION AND VDER PHASE ONE

A. Technologies and Projects Included

1. Staff Proposal

The Staff Proposal suggests that the VDER Phase One tariff apply to projects and technologies that are currently eligible for NEM under the PSL.¹⁷ Those technologies were identified as either 1) intermittent and non-dispatchable, or 2) dispatchable, in recognition of their different characteristics.

The "Intermittent and Non-Dispatchable" category consists of technologies where the operator has no ability to control when the facility generates electricity or at what percentage of its capacity it generates, other than by limiting it or taking it out of service, once it has been put into operation, and includes solar photovoltaic generation, wind generation, and micro-hydroelectric generation. The "Dispatchable Technologies" category consists of technologies where the operator has a meaningful ability to control when, and at what percentage of its capacity, the facility generates, and includes farm waste generation, fuel cell generation, and micro-combined heat and power (CHP) generation.

The Staff Proposal notes that consistent with PSL §§ 66-j and 66-l, eligible projects must have a rated capacity of 2 MW or less, except for CHP projects, which must have a rated capacity of 10 kW or less. Projects must also meet certain other eligibility rules under PSL §§ 66-j and 66-l, including fueling requirements for farm waste generation and compliance

¹⁷ PSL §§ 66-j and 66-l.

with relevant government and industry standards for construction and operation, including compliance with the SIR.

The Staff Proposal recognizes that while a variety of other DER technologies exist, further consideration is needed to determine whether and how the VDER methodology could be applied to compensate those technologies. Staff notes that a number of existing tariffs and programs govern the treatment and compensation of projects that are not eligible for NEM.¹⁸ Specifically, Staff identifies the following categories that should not be eligible for the VDER Phase One tariff:

- Projects larger than 2 MW;
- CHP projects larger than 10 kW;
- Projects involving generation using non-eligible fuel sources, such as natural gas and diesel, other than eligible fuel cells and eligible CHP generators; and
- Non-Generation DERs, such as demand response and energy efficiency.¹⁹

However, the Staff Proposal recommends that the development of future phases of VDER tariffs prioritize inclusion of a broader array of DER.

2. Comments

Several commenters representing non-NEM eligible technologies recommend that the VDER Phase One tariff should apply to a broader category of projects, including some of the technologies that Staff recommends not be included under Phase

¹⁸ For example, buy-back rates provide compensation for net injections and standby rates allow for the output of a generator, installed in-front of a customer's meter, to be netted against the usage of one or several buildings on the premises. In addition, the opportunity to earn compensation via a reliability credit under standby rates is now available.

¹⁹ Customers that are otherwise eligible for participating in Phase One may, of course, also employ non-generation demand response and energy efficiency technologies without losing their eligibility.

One. Referencing the goal of technological neutrality, comments vary with the respect to the proposed timing for expanding eligibility for VDER. While NFG, NECHPI, and NFCRC recommend the inclusion of additional technologies under Phase One from the outset, AEMA, AEEI, NY-BEST, and DEC generally support Staff's recommendation to take up non-eligible technologies as part of the development of subsequent VDER phases and urge that this work commence expeditiously.

3. Determination

At this time, the VDER Phase One tariff will include only technologies and projects that are eligible for NEM. There is a pressing need to transition away from NEM, both to better target DER deployment to meet REV objectives and to manage impacts on non-participants. Many other types of DER, including demand management and response, energy efficiency and non-NEM-eligible DG, are eligible for participation in other existing tariffs and programs that reflect cost-benefit principles. In many cases, these programs have also been the subject of recent reforms to increase their ability to reflect more accurate price signals and compensation consistent with REV goals, including the addition of a reliability credit to standby rates, the expansion of demand response programs, and the development of the Clean Energy Standard. Adding the option to participate in the VDER Phase One tariff without further consideration could lead to overlapping compensation, opportunities for uneconomic arbitrage, and market confusion. Furthermore, as the Staff Proposal notes, technologies eligible for NEM share some basic similarities that not all DER possess, including the ability to produce electricity for on-site usage and for export to the grid, limitations on size, and environmental attributes. To permit other resources to participate in the VDER Phase One

tariff without sufficient consideration of their divergent attributes could lead to unintended consequences.

However, as commenters note, it is a key principle of REV that regulation and tariffs should be technologically neutral and focus on values provided and costs imposed by a DER and their behavior. Therefore, as part of Phase 2, VDER tariffs will be expanded beyond NEM-eligible DG technologies to all DER in a technologically-neutral, value-focused manner as soon as practicable.

B. Inclusion of Energy Storage

1. Staff Proposal

The Staff Proposal notes that energy storage technologies, such as batteries, are not addressed in PSL §§ 66-j or 66-l and recommends that storage be included in Phase One. Specifically, Staff recommends that: 1) projects that pair any energy storage technology with an eligible generation facility, including for the purposes of exporting stored energy, should be permitted to receive compensation under the Phase One tariff; 2) mass market and small wind systems that include storage should be permitted to retain NEM compensation; 3) for CDG, RNM, and large on-site systems, the installation of storage should require participation in the Value Stack, rather than NEM; 4) the presence of energy storage should not result in any change in compensation except that compensation for environmental value and the MTC should only be provided for net monthly exports; and; 5) while the use of system power to charge storage should be permitted, and even encouraged to the extent that it can support the system by reducing peak demand and variability, environmental and MTC compensation should not be provided for the export of stored system power.

The Staff Proposal also suggests that NYSERDA and the utilities examine solar-plus-storage intervention and

demonstration strategies that can help to further monetize system value, especially in high value locations of the distribution system, as VDER Phase One tariffs are implemented. Lastly, Staff recommends that projects that include energy storage but no eligible generator should not be eligible for the VDER Phase One tariff at this time but that a methodology for their inclusion should be developed for implementation at or before Phase Two.

2. Comments

Many commenters, including AEEI and NY-BEST, support Staff's recommendation to include energy storage paired with eligible generators under Phase One noting the importance of energy storage under REV. AEEI, Borrego and SolarCity also stress the importance of taking up consideration of stand-alone energy storage and recommend this topic as a priority; EDF/Policy Integrity suggest that a clear roadmap for doing so, with consideration by the Commission in 2017, is necessary. NY-BEST and TASC are particularly supportive of the solar-plus-storage intervention that is currently being considered by NYSERDA. SolarCity argues that solar projects paired with storage should be permitted to both provide on-site demand and load reduction and export under the VDER tariff. SolarCity also argues that large, on-site projects paired with energy storage should be able to charge on mandatory-hourly pricing even if the customer is not on this pricing scheme; AEEI agrees.

CORE, EDF/Policy Integrity, and Pace comment that Staff's recommendation to provide environmental value only to net exports from facilities paired with energy storage is insufficient to capture the full environmental values associated with energy storage, including the value of shifting load from dirty to less dirty generation on the bulk system. CORE suggests that the environmental value associated with energy

storage should be equivalent to how other clean generation is compensated for environmental value under VDER, which will help to encourage energy storage and further the State's clean energy goals.

3. Determination

The Commission adopts Staff's proposal to include energy storage when paired with an eligible VDER resource. Consistent with that proposal, mass market customers that include storage in their on-site systems will be permitted to retain NEM or Phase One NEM; however, customers that wish to pair storage with a CDG, RNM, or large on-site system will be required to receive compensation based on the Value Stack. While Staff's proposal 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, we recognize that such restrictions may not be reflective of expected storage installation configurations. Because of current federal tax credit rules, most energy storage systems are only charged with renewable power, and therefore the net monthly injection restriction may be unnecessary. Furthermore, the restriction could result in customers with significant usage, clean generation, and energy storage behind a single meter receiving compensation for less environmental value than they actually provide. Staff shall work with stakeholders to identify an alternate option for consideration by the Commission in implementing the Value Stack, such as a commitment by the customer to only charge using the eligible VDER resources, that still avoids uneconomic arbitrage while better reflecting actual storage configurations and value.

As the Staff Proposal and commenters acknowledge, energy storage is a key component of our energy future. The

integration of storage into DER deployments and the utility system has the potential to substantially enhance DER's capability to lower system costs and provide a variety of energy services. In addition to working to include stand-alone energy storage projects within the VDER Phase One tariff as expeditiously as possible, other methods of further encouraging integration of storage, including non-wires alternative projects and demonstration projects, are addressed in the Commission's order regarding Distributed System Integration Plans (DSIPs) considered at the same session as this order.

As noted in the Staff Proposal, NYSERDA is developing approaches to accelerating solar-plus-storage applications through the CEF. Staff shall work with NYSERDA and market participants to develop an Energy Storage Roadmap that identifies current and anticipated electric system needs that energy storage is uniquely suited to address, levels of energy storage that provide net benefit to ratepayers, and market-backed policies, consistent with REV objectives, to build energy storage in New York State.

While commenters' observation that projects that include energy storage could offer certain environmental benefits not recognized in the current Value Stack tariff, such as shifting energy consumption to a time of day when incremental generation is cleaner, is accurate, those benefits may not provide a cost savings to utilities and are not calculable at this time. As discussed further below, as part of Phase Two of this proceeding Staff and interested stakeholders should work to consider whether and how more granular values, including environmental benefits from time-shifted consumption, can be included in VDER tariffs.

C. Accurate Valuation and Compensation of DER

1. Staff Proposal

The Staff Proposal states that a move to monetary crediting is necessary in order to accurately reflect the values created by DER, including locational and temporal values. The Proposal explains that, in contrast to the volumetric crediting methodology currently used for most projects, monetary crediting permits the assignment of an individual value to each kWh based on when and where it is generated.

2. Comments

Several commenters acknowledge the practicality and usefulness of utilizing a monetary crediting structure for the Value Stack tariff. Acadia, EDF/Policy Integrity and Solar Parties specifically support Staff's proposal. SolarCity argues that volumetric crediting of CDG customers is a simpler tool than monetary crediting commenting that they are concerned with the utilities' ability to manage billing complexities.

3. Determination

A major goal of this proceeding, and of REV more broadly, is to develop a precise understanding of the value created and cost imposed by various interactions with the electric system and to then offer accurate compensation for such values, and charges for such costs, in order to provide appropriate incentives for customer and market behavior. At a minimum, accurate valuation and compensation requires the ability to recognize and account for the fact that the value of a kWh can vary greatly depending on where and when it is injected into or consumed from the grid; in other words, to recognize locational and temporal value granularity. As the Staff Proposal states, compensating DER based on locational and temporal granularity, as well as other specific values, requires monetary, rather than volumetric, crediting. For that reason,

compensation under the Value Stack tariff shall be based on monetary crediting.

D. Cost Allocation Principles

1. Staff Proposal

The Staff Proposal explains that, in order to avoid unnecessary reallocation of net revenue requirement between customer classes, recovery for each element of compensation should come from the same group of customers who benefit from the value that the compensation reflects. For compensation that does not reflect a value that has been identified and calculated at this time, including the MTC, Staff suggests that recovery should come from customers within the same service class as the beneficiaries in order to avoid revenue reallocation between service classes.

2. Comments

Many parties support Staff's principles and recommendations regarding cost allocation, including Acadia, JU, MI, Solar Parties, and UIU. Nucor states that cost allocation principles should explicitly state that cost allocation and cost recovery should be linked to and follow cost causation. MI and Nucor ask that additional clarity and specificity be offered for each specific cost allocation recommendation and its implementation.

JU points out that there are several mechanical issues with collection of costs related to various aspects of Staff's proposals, and that general accounting and cost allocation practices vary among the utilities. JU comments that further planning is necessary to implement the cost allocation proposal, and this work will be especially important as the penetration of DER increases.

3. Determination

The Commission adopts Staff's recommendation and directs that costs associated with compensation under the VDER Phase One tariff be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER, as determined in accordance with the Value Stack methodology. For compensation that does not reflect a value that has been identified and calculated at this time, including the MTC, recovery should come from customers within the same service class as the beneficiaries in order to avoid revenue reallocation between service classes.

In particular, compensation for energy and capacity values should be recovered from the same customers that benefit from reduced utility purchases of energy and capacity.²⁰ Compensation for environmental values should be recovered from the same customers that benefit from reduced utility purchases of Tier 1 RECs for CES compliance.²¹ For DRV and LSRV compensation, utilities should identify what portion of the value results from avoided lower voltage level costs and what portion results from avoided higher voltage level costs. The portion of compensation reflecting avoided lower voltage level costs should be recovered from all lower voltage level delivery customers. The portion of compensation reflecting avoided

²⁰ As discussed below, some parties argue that the method chosen for capacity compensation may, at times, result in compensation for capacity within a given utility's territory being higher than the actual capacity value provided by the compensated resources. As part of the development of the Value Stack tariff, utilities should identify, and parties should consider and comment on, whether a method exists to collect any overcompensation from customers within the same service class, consistent with the principles laid out here.

²¹ Tier 1 of the CES requires every load serving entity in New York State to procure RECs associated with new renewable energy resources.

higher voltage level costs should be recovered from all delivery customers. In addition, MTC compensation will be recovered from the service class of the project subscribers for CDG projects, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class.

We recognize that, as JU states, implementing these cost allocation principles will require significant work, including determination of how to effectuate them within each utility's accounting and billing systems. For that reason, each utility shall make a filing by May 1, 2017 explaining their proposed implementation of these cost allocation principles. Those filings will be noticed for comment so as to enable Commission consideration as early as August 2017. While these principles are focused on the billing of costs associated with DER compensated under the Value Stack tariff, the utility filings should also discuss the practicality of allocating and collecting costs associated with DER compensated under Phase One NEM using these principles. Until the Commission has addressed these filings, recovery for compensation under Phase One NEM should continue to be based on current methods used for NEM.

E. Compensation Term Lengths

1. Staff Proposal

Staff recommends that projects retain the compensation methodology in effect at the time they are placed into service for 20 years after their in-service date.²² The Staff Proposal observes that a twenty-year period is consistent with the term of contracts for Tier 1 RECs that NYSERDA will offer through

²² Projects grandfathered under the Transition Plan Order should continue to maintain their compensation mechanism for 25 years from their in-service date.

auctions as part of the CES, as well as with policy trends in other jurisdictions.²³ The proposal also would provide an option for developers or customers to file petitions requesting a longer term than 20 years if pre-existing financing or other contractual arrangements contemplated a longer period. After the 20-year period ends, projects still in operation would be compensated based on the tariff then in effect.

2. Comments

Commenters' views and perspectives on length of compensation term vary. The majority of DER providers, solar developers, and advocates, as well as environmental advocates, including Solar Parties, CCSA, AEEI, DSUN, and EDA, argue that an appropriate compensation term would be equal to the life-of-system, and some argue that at the very least a term of at least 25 years is critical. CCSA posits that many project developers in New York have considered projects as 35-year investments, consistent with the estimated useful life of the current technology. CCSA also argues that Tier One REC contracts should not be determinative for overall compensation term length, which includes more than just compensation for environmental value. DSUN comments that other than already grandfathered RNM projects, NEM projects have not been subject to a term limit.

In the event that term length is shorter than life-of-system, several DER and solar developers, including CCSA and DSUN, are concerned about uncertainty related to the level of compensation after the term has expired, and request that the

²³ See, e.g., California Public Utilities Commission Rulemaking No. 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering, Decision Adopting Successor to Net Energy Metering Tariff (issued February 5, 2016).

Commission adopt a clear statement on post-term compensation in order to appropriately support financing decision-making.

AEEI supports Staff's recommendation to provide an option for developers or customers to file petitions requesting longer terms if pre-existing financing or contractual terms contemplated a longer period. EDA and Grid comment that longer-term rates for CDG are essential to low-income participation.

JU recommends that Staff's recommended proposal of 20-year terms should be shorted to 15 years for mass market customers to reduce long-term risks to non-participants. JU also offers recommendations for term lengths associated with certain components of the VDER Phase One tariff.

MI expresses concern over locking in compensation for a term of 20 years, especially if more precise and accurate methodology is developed under Phase Two. MI also argues that if a 20-year term is adopted, DER developers and customers should not be afforded an opportunity to opt-in to compensation mechanisms under subsequent VDER phases. Other ratepayer advocates, including Nucor and UIU, are also concerned about the long-term locking in of DER compensation and impact on non-participants.

3. Determination

The Commission recognizes that project development requires a reasonable level of certainty in how that project will be compensated. The Commission also recognizes the increased costs and risks that long compensation terms can potentially impose on non-participating customers. However, due to their interconnection status under statutory authority, the Commission will not impose a limited compensation term on customers served under PSL §66-j or PSL §66-l.

For customers served under Phase One NEM, the Commission adopts Staff's recommendation that they receive Phase

One NEM compensation for a 20-year term from their in-service date.²⁴ As noted in the Staff Proposal, this is consistent with other programs and trends in other jurisdictions. As permitted in the Transition Plan Order,²⁵ developers or customers may file petitions requesting a longer term than 20 years based on pre-existing financing or other contractual arrangements that contemplated a longer period. After the 20-year period ends, projects still in operation will be compensated based on the tariff then in effect.

However, as some commenters note, a longer term can lower project costs, particularly with respect to financing, and thereby encourage development at lower levels of compensation, which benefits customers through increased DER deployment at reduced net revenue impacts. While the Commission is confident that the 20-year term length for Phase One NEM will serve as a sufficient incentive for continued project development, in order for projects to achieve economic viability under the Value Stack Tariff, additional support in lowering project costs and financing may be necessary. We therefore adopt commenters' suggestion for a compensation term of 25-years from the in-service date for projects that receive compensation under the Value Stack tariff. While the Commission recognizes the concerns raised by MI, UIU, and Nucor regarding the impacts of any fixed term, the terms established here balance the need for certainty associated with the development and installation of assets, like DER, with an extended productive life.

²⁴ Projects grandfathered under the Transition Plan Order should continue to maintain their compensation mechanism for 25 years from their in-service date.

²⁵ Case 14-E-0151, supra, Transition Plan Order.

F. Environmental Attributes

1. Staff Proposal and Related Issues

The Staff Proposal addresses the treatment of environmental attributes associated with DER in discussing the Environmental Value component of the Value Stack. Staff's proposal that these matters be addressed here is consistent with the Commission's statement in the November 17, 2016 Order in the CES proceeding that "customer participation in the voluntary market and the question of a customer's ability to claim attributes associated with its voluntary projects are issues that are appropriate for further consideration by the Commission, in addition to and informed by the resolution of the transition of behind-the-meter resources from NEM to [a VDER] approach."²⁶

Staff proposes that the generation attributes for which DER generators receive compensation under the Phase One tariff be ineligible from participation in the Renewable Energy Standard (RES) Tier 1 auctions administered by NYSERDA, and from participation in the separate sale of attributes certificates to LSEs or others for RES compliance or other purposes. Staff's proposal is based on the fact that the DER generator (customer-generator or CDG member) is being compensated for the environmental value the DER provides; therefore, the interconnecting LSE that pays for the value should receive a reduction of the obligation of that LSE for RES compliance purposes. Staff proposes that the New York Generation Attribute Tracking System (NYGATS) be used to track the transaction and create appropriate certificates for the account of the interconnecting LSE reflecting the transfer of the generation attributes. To the extent that the Commission determines that

²⁶ Case 15-E-0302, Clean Energy Standard, Order Providing Clarification at 5 fn.3 (issued November 17, 2016).

the Phase One tariff allows customers to claim generation attributes associated with energy consumed on-site for voluntary environmental and sustainability certification purposes, Staff proposes that NYGATS be used to track such on-site generation and to create appropriate certificates for the account of, and for retirement by, the customer. In such a case, the generation attributes retired would not provide any RES compliance credit for the interconnecting LSE, but would be recognized as contributing to the Statewide 50% by 2030 renewable resources goal.

2. Comments

JU comment that the creation of RECs should not be limited to exported generation only and states that generation consumed on-site should also contribute to LSE obligations under the RES. Bloom Energy also argues that generation consumed on-site should be eligible for RES participation. CORE comments that on-site generators should retain title to RECs regardless of the receipt of compensation for Environmental Value. As an alternative, CORE believes that customers should be able to forego payment for Environmental Value and receive fully tradable RECs.

CRS urges the Commission to clearly differentiate between the CES voluntary market and the RES compliance market and argues that no portion of the REC value should be decoupled from contractual REC ownership. CRS is particularly concerned about an automatic counting of renewable generation towards RES compliance without a stipulation that LSEs own RECs from this generation, in that it may erode the benefits of DER to the on-site customer. CRS argues that customers should be presented with a clear choice regarding the selling or transferring of RECs, along with clear articulation of REC ownership rights. NYPA also comments that this customer choice should be provided.

NFCRC is concerned about the lack of clarity around REC ownership.

Pace comments that RECs attributable to DER should not be counted towards either Tier 1 of the RES or the State's overall baseline unless the producer of the REC affirmatively makes a sale into compliance markets. Pace also opposes the restriction on receiving Environmental Value only for net monthly exports and believes that such a restriction will serve as a significant disincentive to customers installing storage.

NYC agrees with Staff's proposal to allow customers compensated under the Phase One tariff to claim the attributes for environmental and sustainability certifications. On the other hand, NYC opposes the restriction in the Staff Proposal that when a customer claims these attributes, the exported generation can be recognized as contributing to the State's overall Statewide 50% by 2030 renewable resources goal but not the RES Tier One obligation. NYC recommends that customer-retained attributes should be recognized as contributing to the RES Tier 1 obligation.

Comments concerning the treatment of DER were also submitted in response to the CES Phase 1 Implementation proposal filed by NYSERDA and Staff in Case 15-E-0302.²⁷ The Renewable Energy Parties (ACE-NY, American Wind Energy Association, Advanced Energy Economy Institute and Northeast Clean Energy Council) stated that further clarification was needed on the eligibility of DER to participate in the NYSERDA Tier 1 REC procurements and that no changes from the initial CES Order on eligibility with respect to DER should occur until the issues are resolved in the VDER proceeding.

²⁷ Case 15-E-0302, supra, Order Approving Phase 1 Implementation Plan (issued February 22, 2017).

IPPNY requested clarification on how DER projects funded by the NY-Sun and other customer-sited tier programs under the RPS would be counted toward the Statewide 50% by 2030 renewable resources goal.

Cypress Creek stated that RECs from DER resources that are recipients of net-metering and the phase one VDER tariff, proposed in Staff's White Paper in the VDER proceeding, be retained and retired by either the project owner or customer and, therefore, not count toward the mandated RES Tier 1 obligations of the LSEs. Instead, it remarked, that the RECs from these projects should be recognized as contributing to the overall Statewide 50% by 2030 renewable resources goal by reducing future LSE compliance requirements.

The National Fuel Cell Research Center and Bloom recommended that the Commission continue to include eligibility of net-metered DER resources in the RES Tier 1 REC solicitations unless and until the VDER proceeding has established appropriately structured REV market signals reflecting the true value of DER.

SRECTrade stated that DER should be allowed to participate in NYSERDA's RES Tier 1 REC procurements noting that solar PV should have access to additional incentives beyond the NY-Sun program.

As noted above, the JU supported the creation of RECs from DER and requested further clarification concerning metering arrangements for DER installations, noting that measurement and verification required for larger-scale installations could be cost prohibitive for many DER projects.

3. Determination

NYGATS was created to track the attributes of electric energy generated in or imported into New York State. Operation of the tracking system results in crediting to NYGATS accounts

and an output in the form of Certificates minted by NYGATS and deposited into the accounts of various NYGATS participants. NYGATS is capable of minting certificates for the attributes of electric energy as of January 1, 2016. Among other things, particular NYGATS Certificates may be designated as transferrable (tradable, sellable and/or monetizable) or non-transferrable (un-tradable, unsellable and non-monetizable), or may be eligible or ineligible to satisfy compliance requirements for governmental, utility, or voluntary market programs of various kinds.

However, even when particular NYGATS Certificates are designated as "non-transferrable," such Certificates may still be transferred in the following contexts and for the following purposes: (a) when the transfer is within sub-accounts of a single NYGATS account, so long as there is no remuneration of any kind associated with the transfer (for example, a company could not transfer credits or certificates to an affiliate, or from one affiliate to another, for remuneration); (b) when the transfer is associated with on-site mass market, small wind, remote net metering, or on-site large projects, the sale of energy or attributes in either a power purchase agreement, lease, or similar arrangement between contractual parties to the subject project to the degree such arrangements are allowed to qualify the customer or customers for participation in NEM, Phase One NEM, or Value Stack compensation and are necessary for the customer to obtain the generation attributes for retirement in the NYGATS account of the customer; and (c) for CDG projects, when the transfer is associated with the sale of energy or attributes in either a power purchase agreement, lease, or similar arrangement between contractual parties to the subject project to the degree such arrangements are allowed to qualify the customer or customers for participation in NEM, Phase One

NEM, or Value Stack compensation and are necessary either for the customer to obtain the generation attributes for retirement in the NYGATS account of the customer or for the interconnecting LSE to obtain the generation attributes for retirement in the NYGATS account of the interconnecting LSE.

The RES component of the CES is one program for which certain NYGATS Certificates will be eligible to satisfy the program's compliance requirements. For example, if the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements. If the NYGATS administrator does not indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements, the Certificate will not be eligible for LSE compliance under RES Tier 1 regardless of the generation attributes stated on the Certificate.

The RES mandate imposes obligations on LSEs to financially support new renewable generation resources to serve their retail customers. LSEs may satisfy their obligation by either purchasing and retiring RECs in the form of NYGATS Certificates where the NYGATS administrator has indicated on the Certificate that it is eligible to satisfy RES Tier 1 compliance requirements, or by making Alternative Compliance Payments to NYSERDA. The RECs may be purchased from NYSERDA from the pool of RECs acquired through central procurement by NYSERDA or obtained through self-supply by direct purchase of RECs from generators or other market participants.

Various voluntary environmental and sustainability certification programs are another example of programs where certain NYGATS Certificates may be eligible to satisfy the program's compliance requirement. For these programs, it is often important to demonstrate that the claimant has acquired

resources that are not also being used to satisfy other mandates such that the claimant's actions evidence true incremental or "additionality" value by voluntary contribution. A Certificate retired in the claimant's account, for which the associated attributes are eligible under the certification program, is often the key indicator necessary to satisfy the compliance requirements of environmental and sustainability certification programs. Typically, those programs require the claimant to retire the Certificates to validate the claim. Given this background, the Commission fully understands the desire of many parties for a clear description of how the Commission will treat environmental attributes associated with DER.

a. Net Energy Metering

As a result of this order, most new DER projects going forward will not be eligible for NEM under the pre-existing NEM tariffs. Behind-the-meter projects that were previously eligible to bid in the Renewable Portfolio Standard (RPS) Main Tier solicitations conducted by NYSERDA will not hereafter be eligible to bid in RES Tier 1 solicitations conducted by NYSERDA unless they made the NEM cutoff established in this order and are actually enrolled in NEM under the pre-existing NEM tariffs. No other behind-the-meter projects of any kind will be eligible to bid in RES Tier 1 solicitations conducted by NYSERDA on a going forward basis. For the behind-the-meter projects that are eligible to bid into RES Tier 1 Solicitations conducted by NYSERDA, if any given the restrictions described above, if they are awarded a RES contract by NYSERDA, NYGATS will mint Certificates for the generator for delivery to NYSERDA's account. Similarly, NYGATS will mint Certificates that will allow generators to perform under all other RPS Main Tier and

RES Tier 1 contracts, beginning January 1, 2016, if appropriate and practicable.²⁸

Customers enrolled in NEM under the pre-existing NEM tariffs, but without an RPS or RES contract, may desire NYGATS Certificates for their own voluntary market purposes. The Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. These customers will not receive any tradable Certificates from NYGATS. For these Certificates to be created, it may be necessary for the affected customers to register the project in NYGATS and provide generation data directly to NYGATS in accordance with the NYGATS operating rules, and possibly to provide NYGATS with a copy of the interconnection agreement. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. The generation attributes of all renewable resource generation consumed by customers in New York State will however contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

b. Phase One NEM

Any DER project that enrolls in Phase One NEM will be ineligible to bid in RES Tier 1 solicitations conducted by

²⁸ All pre-existing NEM projects that are eligible to bid into RES Tier 1 solicitations will be subject to a previous RPS Main Tier contract rule that prohibited simultaneous collections of both New York RPS incentive payments and production-based incentives from any other state or local source, including CST, NY-Sun, and CEF program incentives.

NYSERDA or to receive any tradable Certificates from NYGATS. For customers enrolled in NEM with On-Site Mass Market and Small Wind Projects, Remote Net Metering Projects, and On-Site Large Projects, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. These customers will not receive any tradable Certificates from NYGATS. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. For customers enrolled in NEM with Community Distributed Generation Projects, the customers will be enrolled in a default Interconnecting-LSE-Option unless the customers make a joint non-revocable election at the time of interconnection to opt out and take a Customer-Retention-Option. Neither option involves any change in compensation for the customers, but the Interconnecting-LSE-Option would provide a social benefit to other ratepayers by reducing the cost of RES compliance for the interconnecting LSE. For the default Interconnecting-LSE-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in the account of the interconnecting LSE for the generation attributes ascribed to the energy received by the interconnecting LSE. If the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements and the generation attributes so retired in the interconnecting LSE's account will count towards the interconnecting LSE's RES compliance mandates. For the Customer-Retention-Option, the

Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. As noted above, the generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

c. Value Stack

Any DER project that enrolls in Value Stack compensation will be ineligible to bid in RES Tier 1 solicitations conducted by NYSERDA or to receive any transferrable Certificates from NYGATS. All customers to be enrolled in Value Stack compensation will be enrolled in a default Interconnecting-LSE-Option unless the customers make a joint non-revocable election at the time of interconnection to opt out and take a Customer-Retention-Option. There is a difference in compensation for the customers depending on the option chosen. For the Interconnecting-LSE-Option, the customers will accept compensation for the Environmental Value component of the Value Stack. For the Customer-Retention-Option, the customers will be required to return that Environmental Value compensation to the interconnecting LSE in order to gain an opportunity to participate in voluntary market environmental and sustainability certification programs. These transactions would be conducted seamlessly by the

interconnecting LSE's billing system and the customer bills need only reflect the net result.

For the default Interconnecting-LSE-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in the account of the interconnecting LSE for the generation attributes ascribed to the energy received by the interconnecting LSE. If the generation attributes meet the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificate that it is eligible to satisfy RES Tier 1 compliance requirements and the generation attributes so retired in the interconnecting LSE's account will count towards the interconnecting LSE's RES compliance mandates. For the Customer-Retention-Option, the Commission directs NYSERDA to authorize NYGATS to mint non-transferrable Certificates for deposit and retirement in these customers' accounts for the generation attributes ascribed to them. Because the generator attributes in this category are excluded from meeting the RES Tier 1 requirements, the NYGATS administrator will indicate on each Certificates that it is not eligible to satisfy RES Tier 1 compliance requirements and it will not count towards the interconnecting LSE's RES compliance mandates. Again, as noted above, the generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved.

d. Conclusion

NEM, Phase One NEM, and Value Stack compensation are all linked to the environmental value of the generation attributes that make them eligible for these compensation methods. For NEM and Phase One NEM it is difficult to isolate the exact environmental value in the compensation equation, but

to the degree that those compensation methods allow for the avoidance of fixed costs, the full cost of such avoidance occurs as a consequence of recognizing the environmental value of the generation attributes. While the Commission previously allowed behind-the-meter resources to bid in the RPS Main Tier solicitations conducted by NYSERDA, that decision was made due to the difficulty of devising other viable alternatives for supporting biomass resources. However, continuing to allow dual participation in behind-the-meter compensation programs and RPS is inconsistent with the treatment of environmental attributes in those programs. Now that the Commission is fashioning a comprehensive revision of the NEM regime on the heels of a revision of the RPS regime, the Commission finds that this is an appropriate time to prevent simultaneous participation in both areas, particularly since new opportunities for compensation are being created that are more in tune with REV principles than the legacy solutions. In spite of that the Commission will also allow some small modicum of grandfathering for any behind-the-meter resources that made the NEM cutoff established in this order and are actually enrolled in NEM under the pre-existing NEM tariffs, in order to protect recent investments that may have been made.

Some of the categories being established allow for an element of customer choice as to how the customers will participate. To avoid unnecessary administrative complexities, it is the Commission's intention and requirement that such customer participation choices must be made no later than the time of interconnection so as to inform the interconnecting LSE how to implement the project without causing delay. Similarly, these irreversible decisions will only be allowed on a whole project basis and to all generation injected into the grid by

that project over its lifetime so as to make implementation manageable and predictable.

The platform utilized by NYGATS was originally created to support RPS-type programs, primarily involving large utility-scale generators injecting large quantities of energy into a unified electric transmission system with the quantity of most of the injections already being tracked by an Independent System Operator. The efficient "currency" that developed for such programs is the one-MWh certificate. Despite aggregation opportunities, or to make them possible, as a result of the issuance of this order in many cases it will be necessary to provide periodic certification to customers or to interconnecting LSEs of the generation attributes of quantities of energy measured in fractions of MWh. Therefore, the Commission directs NYSERDA to develop customer accessible monthly reports in NYGATS to include the balance of these generation attributes, inclusive of fractional MWh, in a form which will allow a customer to demonstrate, verify, and certify its claims and functionally satisfy compliance retirement requirements for governmental, utility, or voluntary market programs. NYSERDA is also directed to provide a report within 90 days of the issuance of this order detailing how the NYGATS platform can be used to generate information that will be used to support VDER Phase Two when substantially more tradability will be necessary.

For NYGATS to properly create certificates for a given project, the NYGATS administrator must know a significant amount of information about the project's classification pursuant to the interconnecting LSE's tariff, including the elections made

by the customer, and periodic data regarding the amount of energy generated and/or injected by the project.²⁹

The most efficient method of ensuring that these designations are recognized by NYGATS is for the interconnection agreements to incorporate the required information. For pre-existing NEM or other projects, elections can be made by provision of the existing interconnection agreement along with written notice from the customer to the NYGATS administrator, with a copy to the interconnecting utility.

Until recently, NYGATS was not yet in operation and thus no Certificates were available. In acquiring, at the Commission's direction, the rights to generation attributes NYSERDA effectively claimed ownership of the rights to make environmental claims. In earlier years NYSERDA claimed those rights for a period of years. More recently the claims were made perpetual.

The effectuation of this important new policy requires a change to directions provided and past practice employed under the Customer-Sited Tier (CST) of the now expired RPS program and the more recent NY-Sun program. There, the Commission directed NYSERDA, as the central procurement agent, to acquire the renewable energy attributes for behind-the-meter projects to which it provided financial incentives. Emerging policy considerations and the evolution of REV make it necessary to take a new approach. Effective immediately, NYSERDA shall relinquish all rights to any environmental claims, certificates, attributes or other embodiments or memorializations of those claims for energy produced by any system to which it provided financial incentives under the CST and NY-Sun programs. This

²⁹ As was pointed out by JU in its comments, they do not have "gross production data" for these systems, but they do have data regarding energy injected into the system.

directive to relinquish rights applies both to Certificates minted in NYGATS and to all environmental claims, attributes or other embodiments or memorializations of those claims prior to the commencement of NYGATS tracking. NYSERDA should make reasonably practical efforts to alert past CST and NY-Sun participants of this change. NYSERDA should also work with Staff to consider and implement what changes to existing RPS, NY-Sun and CEF reporting requirements may be necessary to effectuate this change and provide appropriate guidance to all those who may be effected by this change of policy.

For further clarification of the Commission's treatment of generation attributes, a summary table is provided in Appendix B to this order.

G. Opt-In Availability

1. Staff Proposal

The Staff Proposal recommends that all projects that are entitled to continue to receive NEM based on the current policy should be allowed to elect to opt in for compensation under the VDER Phase One tariff instead. Mass market customers and CDG projects that opt in would be placed in the active Tranche at the time of their opt-in decision for the purpose of calculating an MTC. This opt-in would be irreversible and only available before the implementation of a Phase Two methodology. Compensation under the Value Stack requires a utility meter capable of reporting net hourly exported generation. While Staff suggests that utilities should make all reasonable efforts to install such meters for customers that wish to opt in, customers without such a meter would continue to be compensated through NEM mechanisms until such a meter is installed. Staff also recommends that customers compensated under NEM or the VDER Phase One tariff be permitted to opt in to any subsequent tariffs developed in further phases of this proceeding.

2. Comments

The majority of commenters that discuss this issue, namely solar and DER developers and advocates, express general support for Staff's recommendation. MI, however, is opposed to Staff's recommendation, arguing that this presents a "lose-lose" proposition for non-participants and imposes more of a cost impact. Nucor also characterizes the opt-in election as a windfall to developers at the expense of captive non-participants.

3. Determination

Consistent with Staff's recommendation, where a methodology that provides for more accurate valuation and compensation becomes available, customers served under a previous compensation methodology should be permitted to opt in. For this reason, while an opt-in for Phase One NEM is unnecessary because it provides identical compensation to NEM, customers served under either NEM or Phase One NEM will be provided a one-time opt-in to the Value Stack tariff once it is finalized. This allows those customers to access the more accurate compensation offered by that methodology. Furthermore, it will not impose any extra costs on non-participants during Phase One because projects that opt in will be counted towards any relevant caps, as appropriate.³⁰

We will not decide at this time whether and under what conditions customers will be permitted to opt in to future tariffs developed in further phases of this proceeding. That question shall be left for orders related to those future tariffs.

³⁰ We anticipate that opt-in to future phases will similarly not result in additional costs to non-participants.

H. Metering Requirements

1. Staff Proposal

The Staff Proposal explains that a utility meter that can measure and record the net hourly consumption or injection of energy is needed in order to provide temporally granular compensation. Staff therefore proposes that the presence of such a meter be a precondition for Value Stack compensation. Staff notes that many large projects, particularly RNM and CDG projects, are already equipped with such advanced metering.

2. Comments

AEEI and Solar Parties express support for Staff's recommendation to require advanced metering as part of the VDER Phase One tariff. Digital comments that all DERs should be required to install such meters.

3. Determination

The Commission concludes that in order to be eligible for the VDER Phase One tariff, including Phase One NEM, all RNM, CDG, and large on-site projects must be equipped with utility metering with hourly recording capabilities. For new RNM and CDG projects, this metering must be installed at the time of interconnection. For large on-site projects, where an insufficient meter may already be present, the metering should be installed as soon as practicable. While mass market customers served under Phase One NEM are not required to have such meters installed, any mass market customer that opts in to the Value Stack must have such a meter installed before Value Stack compensation can be received.

I. Carryover of Credits

1. Staff Proposal and Related Issues

The Staff Proposal explains that, in any given billing period, a customer may create, or a subscriber may receive, more credits in compensation than the amount of their bill. In such

cases, Staff recommends that the amount will be carried over to the next billing period and applied as a credit on that bill. There would be no limit to the amount carried over by a customer or subscriber, nor would carried over credits be paid out at any time.

In its petition filed on October 21, 2016, SolarCity seeks clarification of how excess credits associated with CDG projects and held by project sponsors will be treated at the end of each annual period. SolarCity asserts that the CDG program rules are unclear insofar as they do not specify whether excess project credits accruing to a project sponsor at the end of the annual period expire, or may be monetized. According to SolarCity, this ambiguity is problematic for project developers because it risks compensating them for less than the full amount of generation produced. This creates uncertainty for financiers, SolarCity continues, which makes it more difficult to secure project financing.

In its petition, SolarCity requests clarification that the interconnecting utility must pay the system average locational marginal cost (LMP) to CDG project sponsors for their year-end excess generation credits. SolarCity argues that PSL §66-j(4)(c) requires utilities to pay CDG sponsors in this manner and, therefore, the "forfeiture" provisions of utility tariffs which effectuate the expiration of excess sponsor credits are incompatible with the PSL and Commission precedent.

SolarCity further argues that federal law also requires that CDG sponsors be compensated for year-end excess generation credits. Specifically, SolarCity explains that the federal Public Utility Regulatory Policies Act (PURPA) requires utilities to buy energy and capacity from a Qualifying Facility (QF) at the utility's avoided cost rate. According to SolarCity, the Federal Energy Regulatory Commission (FERC) has

determined that a QF - including a NEM facility - that makes a net sale to a utility must be compensated at an avoided cost rate. SolarCity asserts that the State's CDG program should be aligned with the federal rules implementing PURPA, as well as the PSL.

2. Comments

No comments on the Staff Proposal substantially discussed this issue or objected to Staff's recommendation.

Pursuant to SAPA §202(1), a Notice with respect to the SolarCity petition was published in the State Register on November 16, 2016 [SAPA No. 15-E-0082SP5]. The SAPA §202(1)(a) period for submitting comments in response to the Notice expired on January 3, 2017. Comments were received from JU and Cypress Creek.

JU opposes the petition. JU asserts that the central goal of the CDG program is to expand customer access to clean, distributed generation. It argues that the Commission required the distribution of all CDG project credits to its members in order to achieve this goal, and appropriately specified how the credits should be allocated or redistributed to project members. This requirement, JU continues, is critical to the CDG program and should be retained. JU argues that the contrary result urged by SolarCity would undermine the Commission's goal of expanding customer access to clean, distributed generation by reducing the amount of clean energy that utilities may resell from the CDG project. According to JU, allowing CDG sponsors to monetize their excess credits: (i) would create an arbitrage opportunity between fixed price contracts with customers and the utility's avoided cost rate; and (ii) could create an incentive for sponsors to spend fewer resources maximizing the project's customer value so that the sponsor may accumulate more excess credits to sell.

CDG developers, JU continues, may elect to sell energy and capacity directly into the wholesale markets rather than enrolling the project in the CDG program. JU argues that, if developers want the benefit of compensation as a QF under PURPA, they should forego the CDG program in favor of participation in the wholesale market. If, however, the project developer prefers to seek compensation for project output under the state-jurisdictional CDG program (and at the higher retail avoided cost rate), then it should accept the CDG program rules as they were established by the Commission.

JU asserts that the CDG program is "in its infancy," with little deployed capacity but a substantial quantity of CDG project capacity under development. JU asserts that it is unclear what effect the year-end excess credit monetization proposed by SolarCity would have on the design, financing, and implementation of the projects under development, or whether SolarCity's proposal would create a competitive advantage for certain resources. JU further notes that SolarCity failed to provide any specific example of the potential harm it describes.

Finally, JU argues that two additional considerations warrant rejecting the Petition. First, to the extent that the Petition suggests that the Commission erred by requiring CDG sponsors to forfeit year-end excess credits, the deadline for rehearing petitions passed more than a year before SolarCity filed its Petition. Accordingly, JU asserts, the Petition is untimely and should not be granted. Second, JU explains that they have made significant investments in billing solutions to implement the CDG program under the rules challenged by SolarCity. The Petition, if granted, would require further investments of unknown amount or difficulty to modify the billing systems. JU contends that the CDG program should be allowed to mature further under the existing program rules,

particularly in consideration of potential changes that may be required by the pending Value of DER proceeding.

Cypress Creek, a community- and utility-scale developer, owner, and operator of solar projects, supports the Petition. Cypress Creek notes that the CDG Order acknowledges that CDG sponsors may not be able to avoid accumulating excess generation credits under certain circumstances. Cypress Creek agrees that sponsors must be compensated for the full value of their generation to enable financing and reduce the risk posed by customer defaults or unexpected terminations. According to Cypress Creek, this creates a minimum value that sponsors may rely on as a backstop, thereby enabling shorter, more flexible subscription lengths and more onerous customer credit requirements. Cypress Creek alleges that it would be difficult for CDG projects to serve low-income customers without the relief requested by SolarCity.

3. Determination

The Commission adopts the Staff Proposal as it relates to the carryover of credits; for a project compensated under the VDER Phase One Tariff, unused credits may be carried over to the next monthly billing period, including over the end of annual periods, with the exception of credits held by CDG sponsors. However, in order to ensure that projects are sized appropriately for the load they are intended to serve, at the end of a project's compensation term,³¹ any unused credits will be forfeited.

With respect to the SolarCity petition, we are persuaded that some additional flexibility may be necessary for

³¹ As discussed above, Phase One NEM projects, other than RNM monetary crediting projects, will have a compensation term of 20 years; RNM monetary crediting projects will have a compensation term of 25 years; and VDER Phase One projects will have a compensation term of 25 years.

project sponsors, particularly with respect to a situation where a large customer drops its membership shortly before the end of an annual period. However, the fundamental purpose of CDG is to expand access to DER to customers who might not otherwise have such access. The restriction on carryover of credits by the sponsor was intended to ensure that CDG projects served customers, rather than serving to produce credits for the sponsor's own use, as well as to avoid the potential for arbitrage.

Compensating sponsors for unused credits, as SolarCity suggests, would improperly allow CDG projects to operate for an extended term without full subscription. Neither PSL §66-j(4)(c), which applies only to a limited category of projects, nor PURPA mandates any such payment. Rather than supporting SolarCity's claim, the FERC case cited in the petition demonstrates that state commissions have broad authority to determine the terms of service for net metered projects.³² As JU states, developers are free to build projects that act as a QF selling energy into the wholesale market, rather than participate in CDG programs, if they prefer PURPA compensation to the terms of those programs.

In order to provide additional flexibility to CDG sponsors while retaining the incentives to keep projects fully subscribed and without creating opportunities for uneconomic arbitrage, CDG sponsors will be given a two year grace period beyond the end of an annual period to distribute any credits they retain at the end of the annual period. If at any time during the grace period the CDG sponsor has distributed all credits in its account, no credits will be forfeited; however, if the CDG sponsor has credits in its account throughout the

³² MidAmerican Energy Co., 94 FERC ¶ 61340.

grace period, then at the end of the grace period it will be required to forfeit a number of credits equal to the smallest number of credits that were in its account at any point during the grace period, since that represents the number of credits that were held over from the previous period. To further ensure that projects are appropriately focused on serving customers, rather than generating credits for later distribution, CDG sponsors will only be permitted to retain credits for distribution during the two year grace period if those credits remain after the sponsor has distributed as many credits as practicable to members, such that each member's consumption in the final month of the annual period is fully offset by the credits provided.

This result addresses SolarCity's petition and also JU's concerns; JU's argument that the petition is untimely does not suggest a different result because consideration of petitions for rule modifications is always within the Commission's discretion and because of the relevance of the issue to this proceeding.

J. Determination of Applicable Compensation Methodology and Transfer of Ownership

1. Staff Proposal

The Staff proposal explains that for mass market, small wind, and large on-site projects, the project is closely tied to the underlying property and the customer as its owner or lessor. Staff concludes that modifying the compensation methodology when a property is sold may impair the value of that property. Furthermore, any transfer of such a property would involve the actual customer moving their residence or business location, and therefore would no longer be able to take advantage of credits generated by the project. For that reason, the compensation methodology of a mass market, small wind, or large on-site project should be determined at the time it pays

25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and should not change during the 20- or 25-year term based on changes in ownership.

For RNM projects, in some cases the project is on land where the customer also has a residence or business location. In other cases, the project may be on a site with no other use and the transfer of a project may not involve a customer moving their home or business. However, in either case, the value of the project is tied with the land once it is put into service. Furthermore, the payment of 25% of interconnection costs reflects a significant investment in the project. For that reason, the Staff proposal recommends that the compensation methodology of an RNM project be determined at the time that it pays 25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during the 20- or 25-year term based on changes in ownership.

For CDG projects, the Staff proposal recommends that subscribers may be added or removed regularly, consistent with current CDG rules, both during the planning and development phases of a project and during the operation of the projects. Using different compensation methodologies for different subscribers would lead to significant complications for the utility and developer and confusion for the subscribers. Furthermore, changing compensation methodologies when there is a change in the owner or operator, where that owner or operator may be the anchor subscriber, the developer, or another entity, would unreasonably change the compensation for subscribers. Therefore, the Staff proposal recommends that the compensation

methodology of a CDG project be determined at the time it pays 25% of its interconnection costs, consistent with the requirements in the SIR, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during the 20- or 25-year term based on changes in ownership or subscription.

2. Comments

No comments substantially discussed this issue or objected to the Staff Proposal.

3. Determination

Staff's proposal presents a rational solution for determining treatment of ownership transfers and therefore it is adopted.

K. Other DER Incentives

1. Staff Proposal

The Staff Proposal notes that DER technologies eligible for the Phase One tariff may also be eligible for a number of other incentives, including federal and state incentives and incentives offered by NYSERDA. Staff recommends that the receipt of any of these incentives not impact eligibility for compensation under NEM or the Phase One tariff.

2. Comments

MI disagrees with Staff's recommendation and argues that receipt of these other DER incentives combined with compensation under NEM or VDER would represent double compensation for the same attributes, in particular environmental attributes. Solar Parties and SolarCity, on the other hand, agree with Staff's recommendation.

3. Determination

The Commission adopts the Staff Proposal as it relates to other DER incentives. It is important to draw a distinction between compensation and incentives. Compensation, including

NEM and the VDER Phase One tariff, is designed to offer DER owners a return for the value that their projects create for the system. Incentives are intended to be additive to, rather than a replacement for, compensation, and reflect a variety of goals and values. To reduce compensation based on the receipt of incentives would subvert the purpose of those incentives and could not be rationally related to the value provided. To the extent that improvements in compensation methodologies, coupled with possible soft cost reductions and continued decreases in system costs, result in a reduced need for incentives, modifications to those incentives can be considered in the appropriate forums.

L. Future Rate Changes

1. Staff Proposal

The Staff Proposal explains that customers that receive NEM have always been subject to changes in rates and in rate design, including increases and decreases in fixed customer charges, allocations between service classes, use of time-based or demand-based rates, and allocation of costs between various billing categories. Staff therefore recommends that customers compensated under NEM or the VDER Phase One tariff should similarly remain subject to such changes. For projects involving multiple sites, such as CDG and RNM projects, this should apply to all sites and meters. Similarly, Staff notes that customers were not and should not be protected from changes in the price of fuel or electricity.

2. Comments

Solar Parties commented in general support of Staff's recommendation. No other comments substantially discussed this issue.

3. Determination

The Commission adopts the Staff Proposal. All customers are subject to changes in rates and rate design, as well as changes in the price of fuel and electricity. The setting of a fixed term for compensation does not freeze other elements of a customer's bill.

IV. APPLICATION OF THE VDER PHASE ONE TARIFF TO THE FOUR MAJOR MARKET SEGMENTS

A. On-Site Mass Market Projects and Small Wind

1. Staff Proposal

The Staff Proposal defines mass market customers as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand. On-site mass market projects include eligible generating facilities connected behind a mass market customer's meter. Staff recommends that on-site mass market projects placed into service before January 1, 2020 continue to receive NEM based on the current compensation methodology. That is, their kWh usage and generation is netted each billing cycle; if their usage exceeds generation, they pay only for the excess usage; and if their generation exceeds their usage, their excess generation becomes kWh credits that offset their usage in the next billing cycle.

For projects put into service after January 1, 2020, Staff recommends that they receive compensation based on the mechanisms to be developed in Phase Two. Should a new compensation methodology not be in place by January 1, 2020, projects put into service after that date would receive NEM compensation only until the new compensation methodology is developed and implemented and would then be transferred to the new compensation methodology.

In addition, for each service territory, Staff proposes a MW trigger reflecting the estimated growth of on-site mass market projects during Phase One. The MW allocation was calculated to sustain activity based on levels and approximate growth trends from 2014-2016. Staff suggests that the rated capacity of all eligible mass market generation interconnected after the date of this order be counted towards this MW trigger, with the exception of wind interconnected before the PSL 66-1 cap is reached. If growth in mass market installations results in this MW trigger being reached prior to the implementation of a new compensation methodology, Staff proposes that the Commission determine what action is appropriate under all the facts and circumstance then applicable. However, reaching the MW trigger would not have any effect on projects put into service prior to any Commission action.

To enable timely awareness of the potential for reaching the MW trigger, Staff recommends that the utilities should be required to provide monthly public reports on the number and capacity of mass market projects as compared to the MW trigger. Furthermore, Staff suggests that the utilities should provide public notice, including notice to Staff, when mass market installations reach 85% of the MW trigger and when the trigger is reached. In addition, Staff proposes that the utilities should expeditiously develop unbundled values, as described below, such that before the MW trigger is reached they can propose new compensation methodologies for consideration.

The Staff Proposal also considers whether other requirements should be imposed on this sector, such as the installation of smart inverters or mandatory participation in Time-of-Use Rates. As noted therein, discussion of smart inverters reflects consideration of how best to address the growth of the installed base of on-site systems compensated

through NEM and of how the value to the system can be maximized. The Proposal recognized that further questions remain regarding smart inverters and recommended that Staff, in consultation with interested parties, present a report and recommendations regarding this topic by July 1, 2017. Topics that could be included, at a minimum, involve the definition of a smart inverter, including operating parameters, and the circumstances under which any requirement should be imposed.

2. Comments

Commenters representing DER technologies, particularly solar companies and advocates, universally support the continuation of NEM for mass market customers as recommended by Staff. Acadia, Pace, NYSEIA, Solar Parties, and TASC all support Staff's recommendation. Many comment that real-time tracking of development under the MW triggers is critical. AEEI cautions that the Staff proposal for continuation of NEM for mass market and its proposal for CDG create a disparity between these two markets segments and customer value propositions.

NYC argues that the MW trigger is not necessary, in particular for the Con Edison territory, and that it introduces material uncertainty into mass market project development, which is especially problematic in New York City where the market is still in early stages. NYSEIA and SolarCity posit that the MW trigger may be hit in some service territories within months after any Commission order and well in advance of the January 1, 2020 date.

While JU does not oppose the Staff recommendation for continuation of NEM for mass market, it argues that any MW triggers should result in concrete and definitive actions as opposed to review by the Commission as Staff recommends. MI and PULP oppose continuation of NEM for mass market and argue that the recommendation carries the concept of grandfathering too far

at the expense of non-participants. Nucor also expresses concern over the impact of continuation of NEM on non-participants.

3. Determination

The Commission finds that continuation of NEM under Phase One NEM for new mass market projects installed before January 1, 2020 is appropriate. Maturation of this market segment and appropriate business models will require notice and a more gradual evolution to a new compensation methodology. In addition, the application of the Value Stack will necessitate more advanced metering than most mass market customers currently have. The rollout of more advanced metering in each utility's territory has been subject to substantial development in other proceedings, including rate cases; attempting to quickly transition mass market DER customers to the Value Stack would disrupt the schedules established in those proceedings. Transition of this sector onto a new compensation methodology will be a component of the Phase Two deliberations, and influenced in part by utility plans and actions to unbundle values.

However, as the Proposal suggests, monitoring will be necessary to ensure that mass market projects do not create the potential for unreasonable impacts on non-participants. Staff's recommendation of a MW capacity allocation, with regular reporting by the utilities and explicit notice when 85% of the allocation is reached, is adopted. Analysis subsequent to the Staff Proposal and informed by comments has resulted in modifications of the capacity allocation sizes. The resulting capacity allocations, as well as the 85% levels, are shown in Table 3, below. The notice at 85% of a utility's allocation will offer the Commission sufficient time to determine whether action is necessary and, if so, what further action should be

taken to manage impact on non-participants. This could result in a variety of possible outcomes, including an accelerated transition to a new compensation methodology, the development of cost mitigators such as grid access charges or non-bypassable fees, or no immediate action if impacts on non-participants do not require further action.

Table 3. Phase One NEM Mass Market MW Capacity Allocation

	<u>CHGE</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>CE</u>	<u>RGE</u>
MWs	30	25	100	20	90	5
85% of MWs	25.50	21.25	85.00	17.00	76.50	4.25

B. Community Distributed Generation Projects

1. Staff Proposal

The Staff Proposal defines CDG projects as consisting of an eligible generating facility located behind a nonresidential host meter and a group of members located at other sites that receive credits from that facility to offset their bills. CDG projects may include both mass market customers and large customers as subscribers. CDG projects are subject to further eligibility rules as described in the Commission's CDG Order.³³ It's expected that most CDG projects will export 100% of their generation to the grid to earn credits to provide to subscribers, but some may be behind the meter of a member and include some on-site usage.

Staff recommends that CDG projects put into service after the issuance of this order should receive compensation based on limited continuation of NEM or the VDER Phase One tariff. These projects are either behind new meters and export 100% of their generation to the grid, like RNM projects, or are

³³ Case 15-E-0082, Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

behind the meter of a large customer, like on-site large projects.

2. Comments

A few commenters, including EDA and smaller DER and solar developers, argue that it is inappropriate at this stage of the CDG market to dramatically shift to a new compensation scheme due to the nascent stage of the market and newness of such Phase One compensation mechanisms. EDA suggests that at the very least, that during Phase One, projects should be afforded the choice to select between NEM and the Value Stack tariff.³⁴

3. Determination

The Commission adopts the Staff Proposal that CDG projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnection costs are paid or the Standard Interconnection Contract executed if no such payment is required.

CDG offers an important opportunity to expand access to DER in New York State, particularly to low-income customers and other customers who otherwise might not have the opportunity to install DG on their premises and participate in DER programs. However, the CDG market in New York State is nascent, with CDG authorized by the Commission less than two years ago and with many projects in the interconnection queue under various stages of development. The Commission is cognizant of the need to avoid taking actions or creating uncertainty that could harm

³⁴ NYC submitted a separate petition requesting waiver of the CDG 10-member minimum, and references that petition in its comments. Case 15-E-0082, supra, Joint Request for Waiver (filed September 1, 2016). That petition is addressed in a separate order.

this market's development, and at the same time recognizes that these projects will be managed by CDG developers, anchor members, or subscriber organizations that have the capability to manage a more accurate compensation mechanism. In recognition of the gap that some projects may face between expected compensation under NEM and under the Value Stack and the need for certainty in the development of the CDG market, the Commission adopts an MTC for CDG projects, which will be divided into Tranches. The calculation of the MTC and capacity allocations for the Tranches are detailed below; as with mass-market projects, the utilities will provide regular reporting on progress in the Tranches and explicit notice when 85% of the allocation is reached.

Because the projects authorized in the separate order addressing NYC's petition for limited waiver of the 10-member minimum are CDG projects and share the necessary characteristics of those projects for Value Stack compensation, including metering capable of recording net hourly injections, they will be compensated in the same manner as other CDG projects.

C. Remote Net Metering Projects

1. Staff Proposal

The Staff Proposal explains that non-residential electric customers, as well as residential customers owning farm operations, may designate net metering credits created by an eligible generator at one property they own or lease to the meters of other properties they own or lease. This process is commonly referred to as remote net metering (RNM). Under the volumetric crediting system adopted in the RNM Volumetric Crediting Order,³⁵ the excess kWh generated at the host site are

³⁵ Case 14-E-0151, supra, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and

transferred to the Satellite Account as volumetric credits, which then offset the Satellite Account's kWh charges, thereby reducing their bill. Staff notes that volumetric crediting results in very low credit value for many customers because a large portion of their delivery bill is a demand charge, which volumetric crediting does not reduce. Therefore the VDER Phase One tariff offers the opportunity to increase compensation for those customers to a more accurate value based on monetary crediting without causing net utility revenue impact. Staff therefore proposes that RNM projects placed into service after the issuance of this order, and not eligible for NEM, should receive compensation based on the Phase One Value Stack tariff.

2. Comments

Several commenters, including Borrego, CORE, and Bloom express concern that under the Staff Proposal large commercial customers, due to their ineligibility for an MTC, will be at a disadvantage as compared to CDG and that current retail rates have proved challenging for DER investment in this market segment.

3. Determination

The Commission adopts the Staff Proposal that RNM projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnection costs are paid or the Standard Interconnection Contract executed if no such payment is required. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate and detailed compensation system. The Value Stack tariff may reenergize this segment, which has struggled to

Establishing Further Procedures (December 15, 2014) (RNM Volumetric Crediting Order).

develop new projects under volumetric crediting. Because, as discussed above, new RNM projects are not expected to cause significant impact on non-participants regardless of whether they are compensated under Phase One NEM or the Value Stack, any project that has a payment made for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order shall be placed on Phase One NEM, with no capacity limit applied. Projects that do not meet this deadline will be compensated under the Value Stack.

D. On-Site Large Projects

1. Staff Proposal

The Staff Proposal defines large customers as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. On-site large projects are eligible generating facilities connected behind a large customer's meter and not used to offset consumption at any other site. Staff recommends that on-site large projects put into service after the issuance of this order that are not eligible for continuation of NEM should receive compensation based on the VDER Phase One tariff for their net hourly exported generation. Generation consumed on-site would not be metered by the utility and would, as is the current practice, directly reduce metered usage and therefore reduce bills rather than resulting in compensation. To the extent that an eligible generating facility that would be subject to the VDER Phase One tariff is interconnected on a site without a meter capable of providing data on net hourly imports and exports, that project should be provided with compensation based on NEM methodology until such a meter is installed.

Staff notes that, to the extent that a customer who has built or builds a project on-site prefers to receive

compensation based on the VDER Phase One tariff mechanisms for all generation, rather than consuming some generation on-site, that customer may arrange for that project to be separately interconnected and metered, such that no generation it produces is consumed on-site but instead all generation is exported to the grid. In that case, as with an RNM project, the customer should receive compensation for all exported generation based on the Value Stack.

2. Comments

Several commenters representing non-solar DER, including AEEI, Bloom, CORE, NFCRC, and OGS express particular concern over the Staff Proposal's treatment of behind-the-meter generation under Phase One. These commenters argue that generation produced and consumed behind-the-meter, as is the case with many large-scale commercial applications, offers many of the same values that the Staff Proposal identifies for net injections. AEEI, for example, urges the Commission to apply the DRV and LSRV to all behind-the-meter generation regardless of whether it is instantaneously consumed or exported. CORE argues that that non-exporting, behind-the-meter generation creates multiple benefits including: 1) avoided or deferred distribution investments; 2) avoided distribution energy losses; 3) reduced wear and tear on the distribution system; 4) avoided environmental impacts associated with transmission and distribution facilities; 5) displacement of diesel generators; and, 6) enablement of grid isolating capabilities.

3. Determination

The Commission adopts the Staff Proposal and directs that large on-site projects be compensated based on a limited continuation of NEM compensation, authorized in this order as Phase One NEM, or on the Value Stack tariff, based on the applicable policy when 25% of a project's interconnections costs

are paid or Standard Interconnection Contract executed if no such payment is required. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate and detailed compensation system. Similar to RNM projects discussed above, new large-scale, on-site projects are not expected to cause significant impact on non-participants regardless of whether they are compensated under Phase One NEM or the Value Stack tariff. Any project that has made payment for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required, within 90 business days of the date of this order shall be placed on Phase One NEM, with no capacity limit applied. Projects that do not meet this deadline will be compensated under the Value Stack.

As commenters note, reducing consumption from the grid by one kWh in a particular location at a particular time through consumption of on-site generation offers identical values to the system as injecting one kWh in the same location at the same time. For that reason, under the principles of REV, a customer should receive equal overall compensation for generating 1 kWh for on-site usage which reduces demand on the grid as for generating 1 kWh for injection as soon as the transition to that end-state can be practicably accomplished. However, a method has not yet been developed to ensure that such customers receive the exact same overall compensation for on-site generation and consumption as for injected generation. Until those methods are developed, customers who currently generate and consume energy behind a meter will get the benefit of bill reductions under existing rate designs.

Therefore, in VDER Phase One, compensation under the Value Stack tariff will only be available for generation injected into the grid, and no compensation beyond the existing

benefit of bill reductions through reduced metered consumption will be offered for energy generated and consumed on-site until VDER Phase Two. To the extent that any customers believe that this results in potential under-compensation for their projects, they can arrange for their DER to be separately metered. In that case, it would not directly reduce their usage; instead, substantially all generation would be injected into the grid and receive compensation based on the full Value Stack leaving them in the same overall financial position as they will be in Phase Two. In order to achieve the technology neutrality and focus on value envisioned by REV, rate design issues will be taken up in Phase Two of this proceeding in order to develop and implement a method for offering equal compensation for reductions in consumption as for generation.

V. THE VALUE STACK

Staff proposes that the VDER Phase One mechanism should compensate customers using a tariff based on calculations (and proxy calculations) of specific value sources as applied to hourly net injections at a utility meter.³⁶ When considered together, these values comprise the Value Stack, with each stated value serving as a component of the stack. Some of the Value Stack's components will be fixed for a given project, while some components will vary with fluctuations in energy markets. The following sections explain each value identified by Staff and Staff's recommended methodology to reflect that value and make determinations accepting or modifying Staff's recommendations. The Value Stack tariff approach results in

³⁶ In addition, and as discussed above, Staff recommends consideration of an initial tranche that would provide limited opportunity for projects put into service after the date of this order to receive compensation based on Phase One NEM.

monetary bill credits that are applied to a customer's or project subscriber's account in each billing cycle, with any excess credit carried over month-to-month, as described above. In order to avoid disruption in New York's nascent CDG market, Staff recommends, and we direct, that the Value Stack tariff also include an MTC that is stepped down over time.

Although commenters offer a wide range of perspectives on particular aspects of Staff's proposed Value Stack mechanism, many parties express general support for the structure of the Value Stack as a strong first step based upon the underlying objectives to transition DER compensation to a more accurate and granular framework. Many parties, including JU and many solar providers, DER providers, and environmental advocates, comment that the overarching structure of the proposed Value Stack tariff would serve as an appropriate step forward from NEM with some critical modifications and if implemented in an appropriate manner, as detailed in prior and subsequent sections of this order.

While consumer advocates express general support for more accurate and precise compensation based on the unique performance characteristics of DER, they articulate concern that the overall Phase One proposal includes too much subsidization for certain types of DER, particularly resulting from the continuation of NEM for mass market and the MTC for CDG projects.

A. Energy Value

1. Staff Proposal

Staff recommends that both the value and the compensation for the energy that eligible generation facilities inject into the system, and the reduction in utility energy purchases resulting from that injection, take the form of actual day-ahead NYISO hourly zonal LBMP energy prices at the time of

generation. Staff suggests that this compensation be calculated in the same way as charges for mandatory hourly pricing (MHP) customers are calculated and, thus, would include avoided losses.³⁷

Staff states that employing hourly zonal LBMP for energy compensation increases the temporal granularity of compensation and has the potential to increase location granularity. It also precisely reflects the costs that utilities are avoiding based on the injected generation. Furthermore, this method of compensation will recognize that some generation technologies, such as solar, may provide electricity at the most valuable time of the day.

2. Comments

There is general acknowledgement by commenters of the logic of this approach. JU, however, argues that injections to the distribution system will not always avoid the loss levels reflected in MHP tariffs. JU suggests that further study be undertaken to analyze and better understand how losses at levels of the system are impacted with the increased use of DG. In the meantime, JU proposes that a lower line loss adjustment be provided considering that most projects injecting into the system under VDER will not achieve the same line loss benefit as behind-the-meter resources. PULP challenges the assertions that DG provides benefits related to reduction in line losses.

Solar Parties, Borrego, EDF/Policy Integrity and OGS support Staff's recommendation and argue for the inclusion of

³⁷ Staff indicates that, to the extent that MHP kWh charges contain adders to collect costs in addition to LBMP and related losses, such as uplift and ancillary services, these adders should not be credited to net injections, as injections do not reduce these costs at this time. These are the types of costs that should be considered for further unbundling, as discussed below, and included in the discussions among DER companies, the utilities, and the NYISO, noted above.

components related to energy, congestion and losses. AEEI and CCR also argue that losses should be included in the valuation of energy.

DSUN argues that the methodology should establish a floor price in order to provide greater certainty under VDER. Solar Parties also note the significant shift that moving from energy value under NEM versus day-ahead LBMP entails. SolarCity comments that it would be appropriate to utilize MHP values as a proxy for energy values under Phase One.

3. Determination

Staff is correct that, at this time, the Day Ahead hourly zonal LBMP, as used in the MHP tariffs, is the appropriate value for crediting DER injections. The Commission notes that JU's Supplemental DSIP filings describe a process wherein the NYISO initiated a pilot project to include a limited number of sub-zonal buses in the calculation of LBMPs which have been published on the NYISO website since late June 2016. We encourage the utilities, Staff, and stakeholders to continue to work on methods to reflect more local and real-time energy valuation mechanisms to provide beneficial price signals to the marketplace.

With respect to avoidable distribution losses, JU would have us treat injections of electricity at specific locations in the distribution system differently from how withdrawals of power are treated at these exact same locations. For withdrawals (i.e., commodity purchases), utility tariffs all provide for increasing bulk commodity costs by a factor to reflect distribution losses. Yet, JU recommends injections be treated asymmetrically – that is, to not increase the bulk energy price by such same level of losses to reflect their avoidance – until studies have been conducted. The Commission disagrees with this approach. Absent a more granular

disaggregation of distribution line losses, it is sensible to conclude that a one kWh injection of power would avoid, on average, the same amount of losses that would be caused, on average, by a one kWh withdrawal.

B. Installed Capacity Value

1. Staff Proposal

The NYISO requires utilities to purchase capacity based on the MW demand on their system during the statewide peak hour of the previous year. Consequently, the actual installed capacity value that eligible generation facilities provide each year depends on their performance during the peak hour in the previous year. Staff notes that the Phase One tariff could base compensation for installed capacity on this value by compensating eligible generation facilities each month with a lump sum equal to their MW performance during the peak hour in the previous year, sometimes referred to as a customer's "capacity tag," multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month.

Staff maintains that dispatchable technologies, as well as intermittent technologies paired with storage, should be able to target performance during this peak period; while the hour itself is not known in advance, it will likely occur during an afternoon on a hot summer day, though it has occurred as late as September. Thus, Staff recommends this form of value calculation and crediting for dispatchable technologies, as well as intermittent technologies that opt in, for example after installing storage.³⁸ Staff argues that any alternative approach

³⁸ Dispatchable technologies, and intermittent ones that opt in, would "be compensated each month with a lump sum equal to their MW performance during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month. In a project's first year, it would receive capacity compensation based on an

to crediting dispatchable technologies would not properly incentivize those technologies to perform during peak hours and would undercompensate those generators who do perform during those hours. Staff acknowledges the difficulties this approach can present and its imperfect match to actual costs and suggests continued engagement with NYISO's processes to improve billing and compensation methods for capacity.

Staff then discusses intermittent technologies not paired with storage, which generally have no control of when they generate. While solar generation, in particular, will generally be producing during summer peak hours, any given project may miss the one particular hour of the year due to uncontrollable, purely random events, such as a poorly timed local cloud.

If credited for ICAP as described above, this would result in substantial variability for intermittent technologies, which could present issues for project financing. In recognition of this challenge, Staff proposes alternative compensation methodologies for intermittent technologies. Staff asserts that intermittent technologies should receive more stable per kWh compensation based on the capacity portion of the utility's full service retail market supply charges. The two specific alternatives proposed by Staff are:

- 1) The capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile could be used for each kWh of generation all year; or,
- 2) Alternately, that capacity portion could be assigned to specific summer hours to better reflect system needs. For this method, each

average generation profile for a project of its technology and rated capacity in its service territory."

June, the prior 12 months of Service Class 1 monthly capacity statements would be used to determine the \$/kW per year. The \$/kW/year amount would then be credited to the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August. Compensation for the ICAP value would be calculated for kWh generation during those hours, and none during other hours. This would result in a similar potential capacity value as providing smaller compensation for each kWh generated all year but would encourage project siting and design focused on peak summer hours.

2. Comments

Commenters submitted wide-ranging viewpoints on Staff's recommendations and alternatives. On the one hand, many commenters, including Solar Parties, Acadia, Borrego, CCR, CCSA, NYSEIA and SolarCity comment that capacity value based upon a single peak hour during the year presents far too much uncertainty and variability and is thus inappropriate for intermittent technologies under Phase One. These parties support Staff's alternative recommendation to base capacity value on the more stable capacity component of a customer's supply charge. Solar Parties, Borrego and SolarCity recommend that SC 1 rates be used as the rates to establish this value and comment that further investigation of appropriate service class load profiles for determining DER capacity value should be taken up under Phase Two. DSUN suggests setting a floor price for the value of capacity.

JU supports Staff's recommendation to link capacity value to performance and are opposed to fixed capacity payments based on a retail supply charge because such compensation may

not accurately reflect the installed capacity value provided to the utility, and its retail customers, by the injections from these resources.

AEEI supports Staff's recommendation to base capacity value on 460 summer hours, indicating that it more appropriately encourages performance in line with system needs. Solar Parties and Borrego support this alternative as an option but not the default approach under Phase One.

AMP says that the capacity value in Staff's proposal will place hydro at a disadvantage considering that, despite having a far higher capacity factor than wind or solar, it often produces the lowest output during the summer months. AMP therefore suggests calculating capacity value based on both a summer and winter peak, or alternatively consider the highest LBMP price as a supplementary peak measurement.

EDF/Policy Integrity comment that the NYISO cost allocation for capacity to LSEs is not aligned with cost causation and is thus a hindrance to efficient DER compensation, which should be further addressed with the NYISO. In the meantime, EDF/Policy Integrity support Staff's second alternative to assign capacity credit to 460 summer hours.

MI and Nucor oppose Staff's alternative recommendations for intermittent technologies, arguing that they unnecessarily subsidize DER developers and customers and are not sufficiently tied to performance. NFG and Nucor comment that the Commission should reject the alternative compensation methodology for intermittent technologies, especially for capacity value, and instead consider a requirement that these technologies pair with energy storage to receive compensation.

Pace expresses concern about the recommendation to link capacity payments for dispatchable resources to ex-post measured performance. SolarCity similarly comments that the ex-

post element of Staff's proposal does not offer sufficient visibility into when to operate in line with system peak.

3. Determination

As JU notes, the compensation recommended by Staff for intermittent technologies may not accurately reflect the installed capacity value provided to the utility, and its retail customers, by the injections from these resources. However, as Staff notes, compensating these technologies through the capacity tag approach could provide a highly variable and uncertain revenue stream to these facilities. That, in turn, could be a serious impediment to the maturation of this nascent market, especially during Phase One of the transition from NEM. Thus, we agree that one of the more stable mechanisms proposed by Staff, both of which rely on retail capacity charges, should be used for intermittent technologies. Alternative 1, above, mirrors the capacity credit currently provided under NEM and thus would be the least disruptive during this transitional phase. Therefore, Alternative 1 should be the default capacity compensation methodology for intermittent resources. Because it focuses the compensation on the 460 peak summer hours, Alternative 2 should be offered as an option to intermittent resources. Finally, intermittent resources should also be permitted to employ the capacity tag approach used for dispatchable technologies. A project may move from compensation under Alternative 1 to Alternative 2 or from compensation under Alternative 1 or Alternative 2 to the capacity tag approach by submitting a request to the utility; however, a project compensated under Alternative 2 may not switch to Alternative 1, and a project compensated under the capacity tag approach may not switch to Alternative 1 or Alternative 2.

The utilities shall work with Staff and other stakeholders to propose, for consideration by the Commission as

soon as Summer 2017, a specific method to implement these approaches. This initial method will include filing of values by May 15, 2017 and filing of updated values by May 15 of each year in Phase One. For this method to provide an incentive over the simple monthly average, the value of capacity in the 460 hour period in the initial filing shall reflect the rate per kWh of collecting all retail customers' (for example, all SC 1 customers') annual capacity costs in those 460 hours. Parties shall work to recommend an improved approach for Phase Two.

Because any approach other than the capacity tag method may credit these facilities for more or less than the ICAP value that their actual exports provide, the utilities are ordered to keep tracking accounts of the comparison of credit amounts to actual ICAP purchase reduction benefits, as those data become available. This will ensure that any net benefits or costs of this compensation methodology can be assigned to or collected from ratepayers in the same service class as the projects creating those net benefits or costs.

For dispatchable technologies, the Phase One tariff shall base compensation for installed capacity on actual performance during the peak hour in the previous year (the capacity tag method). Compensation shall be a lump sum equal to the generator's MW performance during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month.

The Commission acknowledges and agrees with the points raised by Staff and some commenters regarding the imperfection of the current processes for billing for capacity and endorses Staff's recommendation for continued work through the NYISO to improve those processes. In addition, Staff and stakeholders should consider other ways to improve capacity valuation and compensation as part of Phase Two.

C. Environmental Value

1. Staff Proposal

Staff recommends that the Commission find that the Environmental Value of eligible behind the meter generation is at least equal to the SCC as calculated by the U.S. Environmental Protection Agency. However, Staff recognizes that, starting in 2017, the CES will require the purchase of Tier 1 RECs by LSEs. They further note that energy sources included in this proposal are eligible to produce such Tier 1 RECs.³⁹ The CES includes a state goal for clean energy consumption that will be achieved by a combination of mandatory purchases by LSEs and voluntary actions.⁴⁰

The energy exported by eligible DER can provide Environmental Value to LSEs by offsetting the LSE obligation to purchase Tier 1 RECs from NYSERDA or other large-scale generators. The value of that reduction will be equal to the cost of one REC per MWh, or one-thousandth of a REC per kWh. The cost of Tier 1 RECs will be published by NYSERDA as they

³⁹ Staff notes that there are several exceptions. First, CHP generators using non-renewable fuels are not eligible to produce Tier 1 RECs and therefore will not receive compensation for Environmental Value at this time. The eligibility of technologies to produce RECs will continue to be reviewed as part of the ongoing implementation of the CES. In addition, compensation for any Environmental Value provided by technologies that do not produce Tier 1 RECs will be part of Phase Two of this proceeding. Energy storage is not eligible to produce NYGATS Certificates. To compensate projects that combine storage with eligible generation for environmental values for kWh produced by that generation and exported to the grid but not for kWh imported from the grid, stored, and then exported back from the grid, those projects should receive environmental compensation based on their monthly net injections instead of all injections.

⁴⁰ Case 15-E-0302, supra, Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Order).

procure them. Staff believes that, since the purposes of the CES include capturing the benefits of carbon reduction, the Tier 1 REC value should be considered as a substitute for, rather than an addition to, the SCC. While Staff anticipates that the Tier 1 REC price will remain higher than the SCC, it is possible that NYSERDA's latest published sale price of a Tier 1 REC may fall below that amount. Therefore Staff recommends that the Phase One tariff include environmental compensation as the higher of the applicable Tier 1 REC price per kWh generated or the net SCC per kWh value, as calculated by Staff consistent with the BCA Framework Order.⁴¹ Because the NYSERDA CES auctions will procure Tier 1 RECs under long term contracts, Staff would set the Environmental Value per kWh for a given project at a fixed level for a twenty-year period based on the higher of the Tier 1 REC price most recently published by NYSERDA at the time of interconnection or the SCC per kWh value as most recently calculated by Staff at the time of interconnection.

2. Comments

Many commenters, including Acadia, Borrego, CCR, NRDC and Solar Parties support Staff's recommendation to base Environmental Value on NYSERDA's published Tier 1 REC prices and for this value to be fixed for the compensation term. AEEI and EDF/Policy Integrity argue that compensation for Environmental Value should be consistent regardless of whether clean generation is consumed on-site or injected into the system. EDF/Policy Integrity comments that while using the REC price is practical that these prices could be substantially different from the actual damage costs of carbon emissions depending on market outcomes.

⁴¹ Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Framework Order).

MI comments that the Tier 1 REC price is reflective of economic subsidies as opposed to environmental costs or benefits, and thus should not be utilized in any DER valuation methodology that is striving for accuracy. NFG asserts that the Commission should refrain from compensating for the Environmental Value of renewable technologies since all DER technologies, including CHP using non-renewable fuels, should be treated equally under Phase One.

3. Determination

Staff's approach is the most consistent with our prior BCA Framework Order and the intended structure of the CES. Hourly metered injections to the distribution system from eligible facilities receiving Value Stack compensation should receive compensation for Environmental Value based on the latest Tier 1 procurement price published by NYSERDA.⁴² This credit value shall be fixed for the term of compensation for all Value Stack-eligible projects. In turn, these injected MWhs shall reduce the respective utility's Tier 1 REC compliance obligation on a one-for-one basis the customer elects the Customer-Retention option described in the Environmental Attributes Section above, in which case the customer will receive the minted Certificates and will be required to return that Environmental Value compensation received. As discussed above,

⁴² As recommended by Staff as a transition mechanism, Phase One resources shall receive the higher of the Tier 1 REC price or the Social Cost of Carbon, net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values, as calculated by Staff per the BCA Framework Order. NYSERDA recently published the weighted average price as \$24.24 per MWh for its latest main tier solicitation (<https://www.nyserda.ny.gov/main-tier>). As this is higher than the net SCC, this is the value that would be used here until a subsequent solicitation is conducted and price published.

Environmental Value compensation, like the rest of the Value Stack, will be offered only for net hourly injections.

D. Demand Reduction Value and Locational System Relief Value

1. Staff Proposal

Staff states that the Value of DER process has not produced a valuation methodology that identifies and includes all potential distribution system values and this is an area where significant evolution is expected during Phase Two. It notes that further work is required in both data calculation and modeling. As a result, Staff recommends the MTC approach for eligible CDG projects, discussed further below.

However, since, under Staff's proposal, many projects would not receive the MTC, Staff believes these projects should receive an approximate credit for their contribution of value to the local distribution system. Staff proposes to base a DRV credit on the marginal cost of service (MCOS) studies developed by utilities to value peak demand reductions in the Dynamic Load Management proceeding. Currently, compensation for providing this value is available to demand response resources.

Unfortunately, participation in those demand response programs is difficult or impossible for most projects that will be compensated under the Phase One tariff, either because the resource is intermittent and therefore cannot respond to calls in the same way as the dispatchable demand response assumed by the programs, or because the resource is in operation most of the time and therefore acts as "baseload" rather than "response." Staff believes that, while not a perfect match, these can provide a basis for a Phase One DRV credit.

In recognition of the different characteristics of these technologies, a separate method for determining compensation is proposed by Staff. Staff recommends that the MCOS study dollar per kW-year values used for Demand Response

tariffs should be "deaveraged" to enable the calculation of two values for delivery cost savings from demand reduction: the DRV that applies across the service territory and an additional LSRV that would apply to high value areas for a limited number of MWs. Staff proposes that the resulting calculated dollar per kW year will be distributed across the ten highest usage hours in a utility's territory and generators will be compensated based on their performance during those hours. As discussed further below, Staff proposes that, to the extent possible, the values found in the MCOS study be disaggregated to offer more granular locational compensation; furthermore, where that is done, the ten hours chosen would be based on the local peak to the extent possible and appropriate. This compensation would take the form of a monthly lump sum based on the project's kW performance during those ten hours in the previous year. In a project's first year, it would receive DRV and LSRV compensation based on an average generation profile for a project of its technology and rated capacity in its service territory.

Furthermore, Staff proposes that the utilities be required to identify high-value locations, as well as any limitation in the number of MW that are required in those locations, to set LSRVs. A dollar per kW-year compensation would be identified for those areas to reflect the higher value. Staff explains that this compensation represents the value provided in these locations in excess of the DRV, and would therefore be credited to eligible facilities that locate in those areas and are within the required number of MW as additional compensation on top of the MTC or DRV compensation. The higher dollar per kW value identified by the utility would be locked in for the first 10 years for those high-value locations. For all other areas, the dollar per kW value would be subject to modification based on updates to MCOS studies,

increased locational granularity, and deaveraging to reflect the separation of the high-value areas.

As with capacity compensation based on performance during the peak hour, Staff asserts that this compensation mechanism results in uncontrollable quantity variability for intermittent technologies not paired with storage, though the use of 10 hours, rather than one, offers some mitigation. To provide greater compensation stability and further reduce risk, Staff believes the utilities should develop a fee-based portfolio service under which DERs are aggregated into a virtual generation resource with an average nameplate capacity based on the overall capacity and types of resources in the portfolio. The utility would then manage the portfolio to maximize system value and compensate the participants based on that value.

2. Comments

Staff's recommended methodology for DRV and LSRV elicited a range of comments from parties. Solar Parties and Borrego are opposed to DRV as currently proposed, commenting that it is based on incomplete information and requires much more scrutiny and process to properly evaluate and base compensation. These commenters are particularly concerned about financeability. Solar Parties recommend a flat kWh value per utility service territory informed by MCOS studies. Similarly, Solar Parties comment that development of LSRV requires additional and transparent processes, and that developing a proxy value would be appropriate in the interim. Solar Parties and Borrego support an LSRV term of 10-years, but argue that 25-years aligns better with system value.

Commenting that DRV and LSRV are far too uncertain to adopt for Phase One, Borrego recommends basing the DRV off of a 5-year, utility-wide rolling average of similarly performing DERs. Borrego further recommends basing the approach on a

period of greater than 10 peak hours and to permit projects the ability to opt out of the portfolio average. For LSRV, Borrego is also concerned about the process to derive LSRV and their respective locations, and suggests using a proxy value in the meantime based on a multiple of DRV and available for a certain percentage of a utility territory. Solar City shares many of the concerns of Solar Parties and Borrego.

Acadia, NRDC and Pace share similar concerns about the proposed methodology to calculate DRV and LSRV, commenting that the approach will not accurately compensate for distribution values, especially for non-MTC eligible projects. Pace recommends an explicit process to further investigate these values.

While JU is supportive of Staff's proposal to develop location-based compensation, based in part on value to the distribution grid, JU expresses concerns and offers several recommendations. Specifically, JU is concerned about the proposal to subsume distribution value into the MTC for CDG projects, commenting that it locks in a value for far too long and removes any performance incentive for this value component. Alternatively, JU recommends calculating specific DRVs and LSRVs for all DER projects including CDG. JU also comments that any deaveraging to provide an incremental LSRV must also be paired with a corresponding decrease in value to projects outside of the targeted areas. JU recommends unbundling DRV and LSRV and setting for 5 years, with a reset every 5 years using the most recently approved MCOS values.

Non-solar DER developers and advocates, including AEEI, OGS, and NY-BEST recommend that DRV and LSRV compensation should be offered in a consistent manner for both exported energy and generation that is consumed behind-the-meter. These parties comment that failing to do so will significantly

undervalue distribution value offered by behind-the-meter technologies.

MI and Nucor comment that these value components should be explicitly based upon performance and only offered in situations where DER provide a benefit that is sufficient in nature for a utility to rely upon when making system investment decisions and considering potentially avoided costs.

3. Determination

An important aspect of the compensation methodology being adopted is the recognition of locational value, specifically that related to the distribution system. The Commission's goal is to have a methodology that balances per kWh price signals with kW price signals aligned with the system peak, kW signals aligned with local peaks, and price differentials to reflect temporal and locational differences in value. Under this approach, as DER providers work to maximize compensation, they will also maximize benefits to the system. In order to implement a more granular and accurate compensation system, we must move expeditiously so that each individual kWh is assigned an individual value based on when and where it is generated. For this reason, we adopt the DRV and LSRV as part of the Value Stack.

The Commission recognizes that utilities are at the beginning stage of calculating all potential distribution system values. We do note that many distribution system values already exist. While some data is available to determine these values, other data is not yet available for more accurate and granular calculations. Other value streams, such as the benefits of local reactive power or the valuation of quick local response, are currently not modeled in either the wholesale or retail markets. As such, development of DER is constrained due to the

inability to recognize precise values of avoided distribution costs.

However, that does not mean that no value should be credited for contributions to the distribution system. Although Staff's MTC proposal would address this for CDG facilities receiving the MTC, this does not solve the issue for non-CDG projects receiving Value Stack compensation or for CDG facilities with non-mass market CDG members. We are particularly concerned with utility efforts in this area. The utilities, in the first instance, have the most in-depth knowledge of their systems and have access to the planning and operational data necessary to perform such analysis. With unilateral access to the primary data and knowledge of the portions of their systems where load relief would be more or less beneficial, they are gatekeepers of the information. Their comments seem to indicate their acknowledgement of the value of locational specificity, but their lack of progress in developing locationally specific price signals seems to imply a degree of indifference to where, specifically, these facilities will be built during Phase One.

This is not the first time the utilities have been asked to develop methods for determining the granular locational value of DER penetration to their distribution systems. In our Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings, issued December 15, 2014 in Case 14-E-0423, we directed the utilities to design programs that reflect the marginal costs of avoided T&D investments, granular to the network or substation level, if possible, as well as granular load information at the same disaggregated level. In our Order Adopting Distributed System Implementation Plan Guidance, issued April 20, 2016 in the REV proceeding, we noted that the utilities' data processes need to recognize that more

granular data and forecasts will be needed in the future to identify beneficial locations for DER. In the Benefit Cost Analysis Framework, issued January 21, 2016, in the REV proceeding, we directed the utilities to include sufficient information in their DSIPs and BCA Handbooks to inform the developing DER market of system conditions, needs, and granular marginal values so that any solicitations for alternative solutions will be robust. This Value of DER proceeding also requires an examination of granular marginal costs which largely focuses on identifying precise methods in valuing DER benefits and costs as well as new rate designs and valuation mechanisms.

Currently, all utilities have Commission-approved marginal cost of service (MCOS) studies that identify, at the very least, Transmission and Primary Distribution marginal costs at a system-wide level, with some including marginal costs for Secondary Distribution. However, the underlying detail supporting each MCOS study lacks consistency across utilities. Furthermore, system-wide marginal costs simply do not provide the granular price signals needed to achieve value-based and targeted DER penetration. Central Hudson may be closest to meeting the need for a more granular, both spatially and temporally, MCOS study. Central Hudson filed marginal cost studies in the DLM and DSIP proceedings, which include granular estimates for 54 of its 70 substations, as well as Distribution Substation and Transmission at a system-wide level for 2016-2025. Central Hudson's estimates are developed using probabilistic load forecasting at the substation level, essentially providing confidence intervals around capital investments needed to maintain reliability and resiliency. Central Hudson also acknowledges that not all substations or networks are experiencing load growth which would trigger investments. Such an implication suggests that load relief of

any kind (for example energy efficiency, demand response, or DER investment) is more valuable to the extent it relieves constraints associated with a particular substation or Load Area.

Con Edison similarly acknowledges the importance of more granularity and identifies marginal costs separately by identifying six network areas and one non-network area. Although not granular at the substation level, Con Edison's MCOS study developed in its recently completed rate case produced marginal costs by the following regions: Manhattan, Brooklyn, Bronx, Queens, Staten Island, Westchester, and non-network areas. Con Edison then combines those values to arrive at Transmission, Primary Distribution, and Secondary Distribution avoided costs at a system-wide level for 2016-2024. Orange and Rockland's MCOS study methodology is essentially the same as Con Edison's, producing Transmission, Primary Distribution, and Secondary Distribution system marginal costs. However, Orange and Rockland's marginal costs are only presented at a system-wide level for 2016-2032. Similarly, National Grid includes Transmission, Primary Distribution, and Secondary Distribution marginal costs at a system-wide level for 2016-2035. The NYSEG/RG&E MCOS study also includes Transmission, Primary Distribution, and Secondary Distribution marginal costs. However, the NYSEG/RG&E costs are only presented at a system-wide level, and only for 2016.

Although Orange & Rockland, NYSEG/RG&E, and National Grid MCOS studies include granularity of MCOS components (i.e. meter costs, lighting, upstream substation, distribution substation, trunk line feeder, etc.), the studies do not reveal granular, location specific values. Though planned investments due to load growth at particular substations and feeders provide the cost inputs for all the utilities' MCOS studies to date, Con

Edison, O&R, NYSEG/RG&E, and National Grid do not publish the marginal costs by load area or substations. Also, a more probabilistic approach, such as used by Central Hudson, requires load and capacity rating data for each substation. Even Central Hudson only has this information for 54 of its 70 substation areas. National Grid and NYSEG/RG&E are considerably behind in this respect.

The forum for developing marginal T&D cost studies has traditionally been utility rate cases. In recent rate cases, the possibility of modifying MCOS study methodologies to produce more granular and forward looking marginal costs that could be useful for carrying out the objectives of REV have been addressed. This has resulted in a number of rate case joint proposals (JPs) which require collaborative discussions between Staff, utilities, and stakeholders regarding the methodology of MCOS studies for future filings.

Con Edison's JP stipulates that the Company convene with Staff and stakeholders to develop and apply more granular marginal cost studies for not only rate filings, but for other Commission objectives as well. The language in the O&R JP is less prescriptive, but rather states that the Company initiate discussions with Staff and interested parties to identify an agreed upon methodology for future electric marginal cost studies. The NYSEG/RG&E JP charges the Companies to initiate discussions with Staff and any interested parties to review and identify up to three specific methodologies for conducting future electric marginal cost studies, with one of the methodologies reserved solely for the Companies. Neither National Grid nor Central Hudson have language in their respective JPs stipulating a new or updated marginal cost study. It is expected that new marginal cost study information will be included in the Companies' next rate case filing.

Due to the considerable benefit to customers when DERs receive granular price signals, the current misalignment of marginal cost methodologies with the needs of the system has become untenable. The development of granular prices to reflect locational distribution value has not progressed at a pace consistent with the reality of the DER marketplace. Locational indifference now can lead to unnecessary stranded costs in the future, as rapidly improving distributed generation technology outpaces traditional utility response.

The Commission's DSIP Guidance Order required utilities to address the development of tools needed to develop a uniform methodology for calculating the locational value of DERs.⁴³ While the utilities recognize that value assessments that quantify the full set of benefits and services from DER require the development of new data, analytical tools, methods, and a deeper understanding and characterization of salient value metrics driving such analyses, the Commission finds that a more detailed schedule for the development of the valuation methods and tools is necessary for achieving these objectives.

Since a significant portion of the distribution locational benefits are derived through long-run avoided costs of incremental distribution system upgrades, we will require development of those values first. This will form the basis of the information to develop the DRV and LSRV necessary for determining compensation for avoided distribution costs as part of the Phase One Value Stack.

As several parties have recognized, there is a need for much more information, review and process before actual values can be determined. As commenters note, DRVs and LSRVs

⁴³ Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) (DSIP Guidance Order).

are critical to our implementation of the Value Stack, and therefore we direct utilities to file their most recent MCOS studies and workpapers in this proceeding within 10 business days to enable parties to become familiar with the data and information. This shall be followed by the filing of utility Implementation Proposals developed in consultation with Staff and stakeholders, which shall include specific DRVs and LSRVs, by utility, by May 1, 2017. This filing shall include the identification of specific locations and MW caps for the LSRVs. Staff shall establish a process for stakeholder review and comment of the MCOS and Implementation Proposals to enable Commission action by Summer 2017.

Realizing other sources of distribution value - such as the marginal value of distribution voltage and reactive power or the short-run marginal value of distribution constraint management - present increasing complexity and will require continued investment to implement increasingly sophisticated solutions, the Commission requires a detailed schedule from each utility for unlocking those values. Therefore, within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing granular locational prices and values to their distribution systems from DER additions. This plan is intended to provide addition transparency and to facilitate third-party contributions to determination of values. This work should be coordinated with the comparable work underway in the DSIP and BCA implementation processes. A process for review and Commission action on these plans shall be established in as part of the implementation of the Value Stack.

An important feature of the DRV and LSRV approach is the generator performance period. We find that the 10 peak hour approach recommended by Staff appropriately balances the need to

provide certainty to the utility to be able to rely upon the DER when making system investment decisions, with the ability for the DER facility to control its performance.

As for the duration of the DRV and LSRV, we find that the DRV and LSRV shall be determined every three years. The five years suggested by JU is too long of a period given the pace of DER installations and the ongoing infrastructure investments by the utilities. Any project that receives a LSRV shall receive that compensation for a period of ten years as Staff proposes and Solar Parties and Borrego support. Also in accordance with Staff's recommendation, the LSRVs shall have corresponding MW caps associated with them to avoid providing compensation without corresponding benefits. DRVs shall not be fixed, but instead change as they are updated by the utility on the three-year basis.

As Staff proposes, DRV compensation shall not be offered to projects with regard to that portion of the project that receives an MTC, since the MTC, among other purposes, is intended to compensate for unidentified distribution system values. Customers that receive the MTC will remain eligible for the LSRV, since it compensates for defined locational values. For CDG projects that include both small and large customers, as described in the CDG Order,⁴⁴ as members and therefore receive an MTC for only part of the project, DRV compensation should be provided for the portion of the project not receiving an MTC. For those CDG projects that include a mix of both small and large customers, the utility shall value the monthly kWh output of the CDG facility by applying the Value Stack to the percentage of the output allocated to large customers by the developer and applying the Value Stack, plus the MTC but without

⁴⁴ Case 15-E-0082, supra, Order Establishing a Community Distributed Generation Program and Making Other Findings.

the DRV, to the percentage of output allocated to the small customers. The total dollar compensation will then be allocated to the large customers and the small customers using those same percentage allocations.

While we recognize that a performance requirement related to DRV and LSRV compensation presents risk as commenters have stated, Staff's proposed fee-based portfolio service under which DER are aggregated into a virtual generation resource with an average nameplate capacity based on the overall capacity and types of resources in the portfolio should mitigate those risks. Therefore utilities shall develop such options and have them available in time for our implementation of the Value Stack.

We reject comments of non-solar DER developers and advocates, including AEEI, OGS, and NY-BEST, that suggest that DRV and LSRV should be offered for both exported energy and generation that is consumed on-site. As stated earlier, compensation under the Value Stack tariff will only be available for generation injected into the grid, and no compensation will be offered at this time for energy generated and consumed behind a single utility meter. To the extent that any customers believe that this results in potential under-compensation for their projects, they can arrange for their DER to be separately metered and receive compensation under the Value Stack for all generation.

E. Potential Values Not Included

1. Staff Proposal

Staff's Report states that several potential values were discussed during the collaborative process but not included in its proposal. These values include: distribution system values not reflected by the locational demand reduction value, as discussed above; reduced SO₂ and NO_x emissions, to the extent that their damage costs are not already embedded in the LBMP

through existing programs; non-energy benefits, including reductions in CO₂ emissions for reasons other than reduced electric generation, land and water impacts; environmental justice impacts, including reduced local emissions; and wholesale price suppression. Staff also notes that its proposal does not address the ability of customers with behind-the-meter generation to avoid contributing to societal benefits embedded in utility rates or otherwise recovered through per kWh charges, such as low-income discounts and the System Benefit Charge.

Some of the values not included, including currently uncalculated distribution system values and reduced SO₂ and NO_x emissions, will be considered through the Phase Two process. Others, Staff argues, such as non-energy benefits, are not properly addressed through a Value of DER tariff for the reasons noted in the BCA Framework Order.⁴⁵

Finally, for some, no compensation should be offered. In particular, as recognized in the BCA Framework Order, wholesale price suppression is simply a transfer payment, not a resource or societal benefit. When it does occur, it is appropriately recognized as a mitigator of bill impacts, but likely to be an ephemeral one, evident only until the supply side of the market adjusts and prices fall back to sustainable levels. Staff goes on to argue that, in this case, New York State's goals under NY-Sun, the State Energy Plan, and the CES have been broadcast so publicly, and so far in advance of the resource impact, the supply side of the market's planning has already been affected, and will clearly have completely adjusted to the effects of these resources by the time they are in place. Thus, there will not be any market price suppression from adding these clean resources - they will instead simply replace the

⁴⁵ Case 14-M-0101, supra, BCA Framework Order.

fossil-based resources that, otherwise, would have been provided in the market in the future.

2. Comments

Several parties comment on various values that have not been included in Staff's Proposal. Many solar and DER providers, as well as environmental advocates, comment that it will be essential to evaluate and address values that are not identified or calculable at this time as soon as possible. Acadia and NRDC comment that of most particular concern are values related to distribution system value and wholesale price suppression. Cow Power urges consideration of Environmental Value that is unique to anaerobic digestion. EDA argues for the inclusion of additional valuation for reduced particulate air pollution, other contaminants and toxins, reduced water use, environmental justice benefits, reduced energy burden for low-income customers, local job creation, increased resiliency, and ensuring of geographical equity. Other commenters, including Bloom, also comment that Environmental Value related to criteria pollutants should be included in Phase One.

3. Determination

As Staff notes, and consistent with the BCA Framework Order, non-energy benefits are not appropriately addressed through a VDER tariff.⁴⁶ We adopt the Staff proposal on this issue. A process for moving forward on uncalculated distribution system values is described in the appropriate section above; in the work plans required in those sections, the utilities should also include a plan to develop a proposal for identifying and compensating for the value of reduced SO₂ and NO_x emissions.

⁴⁶ Case 14-M-0101, supra, BCA Framework Order.

F. Market Transition Credit and Tranches

1. Staff Proposal

Staff states that some projects are likely to receive equal or greater compensation under its proposed Phase One tariff as compared to what they would receive under current NEM mechanisms. It points to many volumetric NEM and dispatchable technologies as examples. For such projects, Staff recommends that their compensation be set at the Value Stack for Phase One, with a collaborative being created in Phase Two to improve the accuracy of that compensation.

However, other projects, such as CDG solar with no storage, are likely to receive lower compensation under the proposed Phase One tariff as compared to what they would receive under current NEM mechanisms. For those projects, moving immediately to the Value Stack could result in market disturbances. Also, Staff considers the Value Stack to be imprecise in terms of total value provided by generators because it does not reflect full identification of distribution system values. Thus, Staff argues that it is appropriate to provide an additional Market Transition Credit to such projects, bounded based on utility net revenue impact and divided into tranches so that there is a gradual transition to the new compensation mechanisms for CDG solar projects.

Under Staff's proposal, Tranche Zero constitutes those projects compensated under Phase One NEM. CDG solar projects that are compensated under the Value Stack would be eligible to receive an MTC, intended to make their estimated compensation equal to NEM in a first tranche (Tranche 1), 10% less than NEM in a second tranche (Tranche 2), and 20% less than NEM in a third and final tranche (Tranche 3). Further, Staff would apply the MTC to 80% of the generation of eligible CDG projects. The MTC would not be applied to 100% of the generation because the

MTC is based on comparing the value stack to the retail rate for residential customers, while up to 40% of the generation may be assigned to large non-residential subscribers, who may pay a substantially lower per kWh rate. While Staff acknowledges that this may over- or under-compensate a project depending on its actual mix of small and large customers, Staff states that "compensating at 80% reasonably limits any imbalance in compensation while also providing greater certainty and simplicity in Phase One." In addition, Staff explains that this methodology is consistent with the principle that the value of energy should not depend on project membership.

Staff provides illustrative spreadsheet calculations for the MTC for each utility, using data for SC1 customers. In summary, it equated the MTC to the difference between its pro forma calculation of SC1 "NEM" Rates and a similar pro forma calculation of "Value Stack" rates. For its SC1 "NEM" rate estimate, Staff includes the currently effective tariff rates for per kWh delivery charges, SBCs, and MFCs, as well as multi-year averages of per kWh energy and capacity commodity charges. For its "Value Stack" estimate, Staff uses multi-year averages of wholesale LBMP and ICAP values (when applied a pro forma 2 MW solar output curve), and an estimate of the Tier 1 REC value.

Staff proposes the following details for MTCs and Tranches:

1. The MTCs for each tranche should be calculated by each utility and set one time following the issuance of this order.
2. An initial tranche, Tranche Zero, will not require an MTC calculation because projects in Tranche Zero will receive full NEM compensation, as described above. If capacity remains in Tranche Zero after the end of the ninety

business day eligibility period, remaining capacity will roll over into Tranche One.

3. The MTC for Tranche One will be calculated by subtracting the estimated value stack from the current total residential retail rate. However, Tranche One will consist only of capacity rolled over if Tranche Zero is not filled; if Tranche Zero is filled, Tranche Two will follow it.
4. No amount representing the Demand Reduction Value will be included in the Value Stack for the purposes of this calculation because the MTC is intended to subsume the values the DRV represents. Staff states that the use of a fixed kWh MTC rather than a peak-performance-based DRV to compensate certain projects will, among other purposes, respond to developer concerns that application of the DRV methodology would create too much risk and uncertainty because a given year's peak coincident performance is based on factors outside of a developer or customer's control. However, if a project that would be eligible for an MTC wishes to accept the uncertainty of the DRV in exchange for the chance of higher compensation, Staff would allow it to opt out of the MTC and be compensated based on the value stack, including the DRV. This opt-out would be irreversible.
5. The MTC for Tranche 2 will be calculated by subtracting the estimated value stack from 90% of the residential retail rate.
6. The MTC for Tranche 3 will be calculated by subtracting the estimated value stack from 80% of the residential retail rate.
7. If the MTC calculation for a given tranche results in a negative number or zero, there will be no such tranche, and instead prior tranches will be larger.

8. After the final tranche is filled, projects will be compensated based on the value stack associated with the Phase One methodology, including the DRV, and the MTC would no longer apply.

2. Comments

Most parties offered comments on Staff's Proposal to develop and utilize an MTC during Phase One. While the majority of solar developers and advocates support inclusion of the MTC on the basis as a placeholder for values not yet fully identified or quantified, they express concerns over the approach for calculating the MTC along with its applicability under Phase One.

Solar Parties are specifically concerned about the Staff proposal to offer MTC to only 80% of the generation from an MTC-eligible project, commenting that this combined with the compensation tranche step downs will result in anemic CDG growth. NYC comments that this approach would result in an inappropriate and immediate reduction in value as compared to on-site rooftop solar. CCSA comments that an 80% MTC combined with the proposed tranche step downs will not support CDG development upstate and may not support development in later tranches downstate.

Solar Parties argue for step down from the retail rate of 5% per tranche as opposed to Staff's recommendation of 10%. Solar Parties further comment that the MTC should be applied to 100% of generation because the value to the distribution system from a CDG project will be the same regardless of CDG customer composition.

With respect to the calculation of the MTC, Solar Parties, Borrego and CCSA suggest that LBMP data from 2016 should be used to calculate the MTC in that historical data does not accurately represent the commodity prices that CDG projects

will be exposed to. The majority of these parties also support setting the MTC at one time at the beginning of Phase One and recommend that this should be conducted by Staff in a transparent manner.

JU comments that the MTC should only be offered for a period of 10-years as opposed to the 20-year term recommended by Staff. JU also asserts that there needs to be significant improvements made in the accuracy of data and inputs used to calculate the MTC, including using the same values for LBMP and capacity in both the Value Stack and calculation of MTC to avoid unnecessary distortions. JU is concerned that an 80% MTC would lead to payments greater than current NEM compensation for some customers, including large-commercial customers. Alternatively, JU recommend that the MTC be applied based on the actual mix of CDG customers. JU is also concerned that given CDG project economics, the MTC will impose more cost impact on non-participants than is necessary to stimulate market development. Solar Parties along with many solar developers and advocates object to the JU claim of excessive profit margins.

MI and Nucor are opposed to the concept of an MTC, commenting that the approach perpetuates unnecessary subsidies for DER and is inconsistent with the objective of the VDER proceeding to develop more accurate and granular valuation.

CORE comments that the MTC should apply uniformly to all commercial-scale projects, not only CDG.

3. Determination

We find that the general approach of gradually declining MTCs, associated with fixed-MW-size Tranches based on limitations of impacts on non-participants as discussed above, to be an appropriate transition mechanism. However, to avoid the possibility of a cliff or market interruption, similar to the mass market trigger, when 85% of the total MW capacity

allocated to all Tranches is reached in any utility territory, that utility shall provide notice to the Commission so that the Commission can consider what further steps should be taken and until further Commission action, projects that interconnect will continue to be placed in Tranche 3.

Further, the tariff elements and general method of calculating the MTC described in Staff's Report are sensible, with the following changes. Consistent with our decision above regarding the calculation of the 2% revenue impact target, three-year averages should be used for all but the per kWh delivery tariff element. The latter shall be based on the currently effective level. However, in this case, all averages shall be weighted by the output levels in the pro forma photovoltaic profiles filed with the Staff Proposal, as these better represent average values that would be received under NEM. Thus, the volumetric delivery elements and calculation methods for MTC calculation shall be:

- A. SC1 and Small (i.e. non-demand-metered) Commercial Tariffed Volumetric Delivery Rates per kWh. Calculated as the volumetric delivery rate element that is effective on the date of this order.
- B. SBC Rates per kWh. Calculated as the weighted average per kWh SBC rate relevant to each service class for the 36 months in the years 2014, 2015, and 2016. The weights used for calculating this average are the monthly kWh produced by the pro forma PV profiles for a 2 MW system in each service territory, provided by E3 and filed with Staff's October Report.
- C. MFC Rates per kWh. Calculated as in B.
- D. Capacity Rates per kWh. The portion of the retail commodity charge designed to collect NYISO capacity costs for each of the two services classes. Calculated as in B.
- E. Retail Energy Charges per kWh. The retail commodity charge minus the capacity portion described in D. Calculated as in B.

The sum of elements A through E, above, will establish the pro forma "Base Retail Rate." For the purpose only of setting the MTC, the following elements and calculation methods shall be used to calculate the "Estimated Value Stack":

- F. Environmental Rates per kWh. Based on the most recent NYSERDA Tier 1 REC procurement, this shall be set at \$0.02424 per kWh.
- G. Capacity Rates per kWh. Calculated exactly as in D, above.
- H. DA LBMP Rates per kWh. The hourly Day Ahead Locational Based Marginal Prices for all hours in the years 2014, 2015, and 2016. Calculated as the hourly PV kWh weighted average price for all hours in the above years.⁴⁷ (For the purposes here, the prices for February 29, 2016 shall be ignored to comport with the pro forma PV curves.)

The MTCs shall be the difference between the above "Base Retail Rate" and "Estimated Value Stack." A table showing estimates of these values for each utility for SC1 is attached as Appendix A to this order. Utilities shall file by May 1, 2017 the final calculations of these MTCs, for both SC1 and small non-demand metered commercial customers, following the methods above.

Although the value of a CDG project ultimately should not be based on the rate class of members, we find that Staff's proposal to credit the MTC to 80% of a project's exported output, regardless of the actual makeup of its member customers, is too prone to over- or under- compensation. The MTC compensation shall reflect the actual mix of mass market customer members, as reflected by their percent entitlement to

⁴⁷ For Central Hudson and Orange and Rockland, NYISO Zone G DA LBMPs shall be used. For Rochester Gas and Electric, Zone B DA LBMPs shall be used. For Consolidated Edison, an hourly average of Zone J, Zone H, and Zone I DA LBMPs shall be used. For New York State Electric and Gas, an hourly average of Zones A through G DA LBMPs shall be used. For National Grid, an hourly average of Zones A through F DA LBMPs shall be used.

output credits. Because mass market members may be either residential or small (i.e. non-demand metered) commercial customers, two MTCs, one for each service class, shall be defined and calculated for each utility to reflect each of these rate classes. As described above, DRV compensation will not be provided for the portion of any project that receives an MTC, but will be provided on a pro-rata basis for the portion of any project that does not receive an MTC.

To create a gradual transition from 100% NEM to more value-based compensation, the total capacity allocated to CDG projects built during Phase One, as shown in Table 2 above, shall be made available according to the compensation Tranches shown in Table 4, described here. Tranche 0 constitutes the capacity allocation available in Phase One NEM for CDG projects. Any capacity remaining in Tranche 0 after the 90 business day deadline for determining eligibility for Phase One NEM will be allocated to Tranche 1. Projects in Tranche 1 will receive Value Stack compensation with a per kWh MTC derived by subtracting the Estimated Value Stack from the Base Retail Rate, as described above, such that compensation in Tranche 1 is approximately equal to compensation under Phase One NEM.

Once the Tranche 1 allocation has been reached, projects will be placed in Tranche 2 and receive Value Stack compensation with a reduced MTC. We agree with the commenters that argue that Staff's 10% reduction in compensation from Tranche 1 to Tranche 2 is too large and instead adopt a 5% reduction. Thus, the per kWh MTC for projects in Tranche 2 will be derived by subtracting the Estimated Value Stack from a number equal to 95% of the Base Retail Rate.

Finally, when the Tranche 2 allocation has been exhausted, projects will be placed in Tranche 3, which will receive Value Stack compensation with an MTC intended to result

in a further 5% reduction in total compensation. The Tranche 3 per kWh MTC will be derived by subtracting the Estimated Value Stack from a number equal to 90% of the Base Retail Rate.

The total capacity allocated to CDG projects built during Phase One, as shown in Table 2 above, was allocated among these Tranches as follows: For utilities with a total capacity allocation for CDG projects greater than 100 MWs, 25% of that allocation was placed in Tranche 0. For utilities with a total capacity allocation for CDG projects less than 100, 50% of the total incremental MWs were placed in Tranche 0. The portion of the Tranche 0 capacity allocation that is not exhausted during the 90 business day period for determining eligibility for Phase One NEM, if any, shall be assigned to Tranche 1. The remaining capacity allocation is allocated approximately evenly to Tranche 2 and Tranche 3, rounded to even MW numbers. As noted, these represent, respectively, 95% and 90% of expected compensation in Tranche 1.

Table 4. INCREMENTAL CDG MWs BY TRANCHE

	<u>CHGE</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>ConEd</u>	<u>RGE</u>
Total Incremental CDG MWs	77	47	474	223	548	111
Tranche 0/1	39	23	119	56	137	28
Tranche 2	19	12	178	84	206	42
Tranche 3	19	12	177	83	205	41

Table 5, below, shows the estimated annual net revenue impact in each service territory of the VDER Phase One Tariff, if the capacity allocations for Phase One NEM for mass market projects and all three tranches are filled. Table 5 demonstrates that the estimated impact is approximately 2% or less in all service territories.

Table 5. Estimated Revenue Impact Given Ordered Tranches						
	<u>CHGE</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>ConEd</u>	<u>RGE</u>
Continuing On-site	\$1,277,756	\$1,454,425	\$3,004,666	\$628,541	\$5,107,973	\$162,662
Tranche 0/1	\$3,052,905	\$2,563,976	\$5,776,581	\$2,877,094	\$14,836,244	\$1,508,026
Tranche 2	\$1,016,400	\$993,677	\$4,153,361	\$2,153,150	\$15,901,750	\$1,178,239
Tranche 3	\$838,369	\$847,153	\$2,766,065	\$1,471,689	\$12,821,527	\$824,366
Total	\$6,185,430	\$5,859,232	\$15,700,673	\$7,130,475	\$48,667,495	\$3,673,292
Total SC1 kWh Revenues	\$300,479,547	\$283,738,460	\$1,310,994,991	\$515,208,388	\$2,822,430,784	\$275,242,570
% of kWh Revenues	2.06%	2.07%	1.20%	1.38%	1.72%	1.33%
NOTES						
	1. Tranche 0/1 conservatively assumed to consist entirely of Tranche 0 projects					
	2. 50% of Tranche 0/1 RECs are assumed retired, thus not offsetting compliance					

What Tranche a project falls in, including whether it is eligible for Phase One NEM as part of Tranche 0, shall be determined at the time it submits its payment for 25% of interconnection costs, or at the time it executes a Standard Interconnection Contract if no such payment is required. Utilities should provide frequent and transparent reporting on the progress of the Tranches so that CDG developers can make informed decisions with respect to pursuing tranche eligibility. This is especially the case for Tranche 0, Phase One NEM, which will be open and available soon after the effective date of this order. To ensure an orderly allocation of Tranche 0 capacity in each service territory during the ninety business day period, each utility shall file, within 7 days, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs. The utilities shall expeditiously develop a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall periodically file letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.

Similar to the mass market trigger, when 85% of the total MW capacity allocated to all Tranches is reached in any utility territory, that utility shall provide notice to the Commission. The Commission will then consider what further steps should be taken. Until further Commission action, projects that pay for 25% of their interconnection costs, or has execute their Standard Interconnection Contract if no such payment is required, will continue to be placed in Tranche 3,

even if the capacity allocation established for Tranche 3 is exceeded.

VI. IMPLEMENTATION OF VDER TARIFF AND FURTHER PROCESS

As described above, this order directs that all projects interconnected after the date of its issuance, with limited exceptions, be served under the VDER Phase One tariff rather than currently existing tariffs. To effectuate that, each utility is directed to file tariff amendments to be effective on April 1, 2017 on not less than 5 days' notice consistent with the decisions regarding NEM and Phase One NEM in this order.

To enable the full implementation of the VDER methodology through the Value Stack, the Commission intends to issue a Value Stack Implementation Order as soon as Summer 2017. To ensure the Commission has the necessary information to do so, we direct utilities to make specific filings and to develop an Implementation Proposals in consultation with Staff and stakeholders and file those Proposals for public comment, which will enable the Commission may consider and act on the relevant matters no later than Summer 2017. Staff should work with the utilities and stakeholders to organize consultative meetings in advance of and, as necessary, following the issuance of the Implementation Proposals.

In order to ensure that activity under the VDER Phase One tariff meets stakeholder expectations and New York State's needs for aggressive DER deployment, as well as to monitor for unintended consequences, Staff shall conduct a review of initial progress and file a report on that progress within six months of the issuance of this order.

Utilities are required to make the following filings:

1. Each utility shall file tariff leaves implementing the transition from NEM to Phase One NEM, as part of

the VDER Phase One tariff to be effective on April 1, 2017 on not less than 5 days' notice. Newspaper publication of these compliance tariff filings shall be waived.

2. Each utility shall file a letter within seven days recording the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017.
3. Each of the utilities must file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory.
4. Each utility shall file, within 7 days, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs, as well as the number of CDG projects and the MW of capacity represented by those projects that paid 25% of their interconnection costs between the issuance of the order and the filing of the letter. The utilities shall expeditiously develop a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall file regular letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.
5. Each utility shall file their most recent MCOS studies and workpapers within 10 business days.
6. Within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions.

By May 1, 2017, each utility shall file an Implementation Proposal for public review and comment, followed by Commission consideration. The utility Implementation Proposals shall include, at a minimum:

1. Calculation and compensation methodologies for DRV;
2. Identification of, compensation for, and MW caps for 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 this order;
7. Proposed accounting transactions and ratemaking treatment related to the implementation of this 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 body of this order. This filing should include rules on how the MTC, DRV and LSRV will be applied to CDG projects.

A. Commencement of VDER Phase Two

At the outset of the collaborative meeting, the parties agreed that recommendations for a Phase Two of the VDER methodology would be developed as soon as practical following

the completion of the Phase One deliberations. The Staff Proposal recommends the development of Phase Two methodology by the end of 2018.

The Commission endorses that timeframe. Request for comments addressing the design of the Phase Two process was issued on November 18, 2016 and comments were received on December 23, 2016. The Commission recognizes that it is important that work begin immediately. Therefore, a procedural conference or other meeting of interested parties will be convened during May 2017 to commence Phase Two. The meeting should include consideration of the process for Phase Two, which should give due consideration to the comments filed on December 23, 2016. We anticipate that the scope of Phase Two will include, at a minimum, the following topics: 1) inclusion of DER projects in VDER tariffs on a technology-neutral basis; 2) development of methods to provide equal compensation for reduced consumption and injected generation; 3) a framework for the development and consideration of grid access charges, non-bypassable fees, or other methods to mitigate costs imposed on non-participants; 4) potential changes to default rate design and development of optional rates for VDER participants; 5) improvements and modifications to the Value Stack, including components related to the bulk system, distribution system and societal values; and, 6) transitioning of mass market projects to VDER. An agenda will be issued at least five days before the meeting. We anticipate that these topics may be further refined, either through the agenda or another notice issued prior to the first meeting or thereafter as a consequence of further input from stakeholders.

Commission action on recommendations developed during Phase Two need not wait until the completion of consideration of all topics. Rather, the Commission will entertain

recommendations as they are available. In particular, consideration of 1) project and bill impact cost mitigation initiatives that are not presented as part of the implementation order and 2) inclusion of DER projects in VDER tariffs on a technology-neutral basis should be given priority such that they can be brought to the Commission while other Phase Two proposals are still under development.

B. Enabling Participation of Low-Income Customers in VDER Programs and Tariffs

Maintaining the commitment to promote affordability of electric service and opportunities for low-income customers to participate in clean DER, the Commission's adoption of a CDG policy was premised in part on broadening access to renewables, including serving low-income customers. In adopting CDG, the initial Phase 1 of the program included a project eligibility option of 20% low-income off-takers for a given project. While, there was no uptake or development of projects under this stipulation, we stand by our commitment to pursue solutions to encourage low-income customer participation as discussed below.

In addition, as part of CDG adoption, we directed a CDG Low Income Customer Collaborative to investigate barriers and solutions for low-income customer participation in the anticipated CDG market. While we appreciate the work of the Collaborative, it did not result in viable solutions or recommendations for supporting and/or removing barriers to low-income customer participation in CDG.

We finally note that NYSERDA's low-income solar program for low-income, single family residences under CEF is currently being reevaluated due, in part, to the modest uptake under this program. We appreciate and support NYSERDA's investigation into new program options, including ways to encourage and incent low-income customer participation in CDG

projects. Their efforts are critical in order to ensure successful market intervention in this sector.

While recognizing the various ongoing efforts focused on this important topic, consistent with our underlying objectives in REV and our continued commitment to broaden access to clean energy for low-income customers, the Commission directs near term actions as well as additional process to continue these critical investigations. We acknowledge the comments of the EDA and agree with them that CDG continues to offer great potential for broadening access to clean energy to low-income customers. Our actions in this order recognize both the critical need to address these issues with near-term intervention as well as the fact that there remain persistent challenges in this market segment despite the efforts discussed above.

First, consideration should be given to an interzonal CDG credit program designed to provide benefits to interested low-income customers from CDG projects interconnected in service territories and load zones other than their own. Such a program could offer the potential to serve low-income customers in areas, such as New York City, that have proven challenging for development of larger scale CDG projects that benefit from economies of scale. While we acknowledge the added administrative challenges of implementing an interzonal CDG credit program, including those associated with utility billing and crediting mechanisms, we believe it merits serious consideration at this time. We therefore direct Staff to work with NYSERDA, the utilities, and other stakeholders to develop a report on the feasibility of an interzonal CDG credit program.

In recognition that the interzonal CDG credit program will require deliberate development and consideration, the Commission will take the following two actions, which hold the

potential to have more immediate impact. First, the Commission directs Staff to work with NYSERDA as they continue their investigation into alternative program design options for their low-income solar programs, and specifically directs consideration of whether reallocation of CEF funding dedicated to encouraging and incentivizing low-income participation in CDG projects is appropriate and whether additional funding should be dedicated to those areas, balancing the consequences and foregone benefits of these reallocations and considering the required adjustments to CEF outcomes. Upon a determination that program changes are warranted, we anticipate that NYSERDA will file a new or revised CEF investment plan with Staff, as appropriate.

As we adopt this suite of measures to address barriers to low-income customer participation in CDG, it will be essential to also consider financing solutions and credit issues related to these customer segments. The Commission therefore directs Staff to work with NYSERDA to continue to explore New York Green Bank options, including but not limited to developing solutions to lower the cost of capital and provide credit support for CDG projects that are either fully or proportionally comprised of low-income customers. In particular, the investigation of options through the Green Bank should include consideration of solutions that can support local community-based investment into CDG projects.

To help overcome additional financial barriers for low-income customer participation in CDG projects, during the implementation phase for VDER Phase One tariffs, consideration will be given to other options to incentivize and encourage low-income customer participation in CDG, including tailored approaches for CDG projects for which low-income customers compose a majority of off-takers.

In consultation with stakeholders, Staff shall develop and file, by September 1, 2017, a Low-Income CDG Proposal, which shall include, at a minimum, information developed through the CDG Low Income Customer Collaborative, a report on the feasibility of an interzonal CDG credit program, and discussion of the other options to encourage and support low-income customer participation discussed above. That Proposal will be filed for public comment followed by Commission consideration and action.

C. Oversight of DER Providers

The Commission recognizes the comments of UIU related to DER oversight. Specifically, UIU comments that in conjunction with the VDER proceeding, it is important to formally recognize parallel proceedings regarding consumer protections, including establishing a set of Uniform Business Practices for DER providers and considering DER performance bonds as a consumer protection measures.

The Commission's DER Oversight proceeding was initiated in the Order Adopting Regulatory Policy Framework and Implementation Plan, issued February 26, 2015 in the REV proceeding, and advanced through a Staff Proposal filed on July 28, 2015. The DER Oversight proceeding has focused on the design, structure, and level of supervision of DER providers that will be appropriate to ensure consumer protections, while at the same time enable markets to develop through fair competition. Staff has conducted a substantive discussion with stakeholders regarding the advantages, benefits, detriments, and other aspects of various approaches to DER oversight. With the anticipation of CDG development and broader DER markets, there is a need to refresh the work that has been accomplished to date.

Therefore, the Commission directs Staff to file within 30 days an updated whitepaper on DER oversight for public comment so that the Commission will be able to consider the DER oversight provisions at the same time as it acts on the implementation issues in this proceeding.

D. Mitigation of Bill Impact and DG Project Costs

While this order establishes a control on bill impacts resulting from the implementation of VDER Phase One, other mechanisms may be available to reduce project development costs, enabling a reduction in the MTC. Such actions can also have the effect of enabling additional projects within a utility service territory without exceeding the bill impact ceilings established by this order. For example, the Green Bank may be able to offer financing of DG projects that enables a project to accept compensation from a higher Tranche, and therefore lower the MTC and resulting bill impacts. Other actions can have the effect of lowering CDG project development costs, thereby enabling additional projects to proceed within the Tranche size limits established here.

The following are examples of barriers to development that can be addressed to expedite soft cost reduction as the market scales. Addressing these barriers could meaningfully reduce soft costs to New York's CDG industry. To promote soft cost reductions in the CDG market, Staff is directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal or proposals for steps that can be taken to reduce, eliminate, or mitigate market barriers. To the extent feasible, proposals should be developed for consideration by the Commission as early as Summer 2017 as part of the Phase One implementation order. Otherwise, proposals will be addressed by the Commission as they are ready for consideration.

To ensure continuous activity and growth in the DER market as these options are developed, the Commission directs NYSERDA to develop and file CEF investment chapters as soon as feasible that can provide additional support as determined necessary by NYSERDA in consultation with Staff, with specific consideration of providing support to Tranches 2 and 3. The purpose of these investments will be to ensure the viability of the solar market during the Phase One transition, while transitioning the market to align with underlying goals of the VDER process.

a. Development costs:

- i. Project size: DER projects, and CDG projects in particular, benefit substantially from economies of scale. Allowing projects larger than 2 MW to participate in the VDER program could significantly lower per-MW costs. This should be a priority item in the Phase Two process and should be presented to the Commission as expeditiously as possible.
- ii. Financing costs: New York Green Bank, in consultation with NYSERDA and DPS Staff, shall explore and seek to offer to financing to developers who voluntarily opt into higher tranches that has more efficient terms which can help offset some of the economic effects of opting into those higher tranches.
- iii. NY-Sun incentives: NYSERDA, in consultation with DPS Staff, shall explore adjustments to the current and future blocks of the MW Block Design that continue existing incentive levels for longer, and correspondingly decrease future incentive levels on the basis of future improved

economics of solar projects as a result of the cost-reducing actions being advanced in other parts of this order.

iv. Use of utility property: Staff, utilities, developers, and other stakeholders shall consider options for leasing or other arrangements allowing the installation of DER on utility property.

b. Consolidated Billing:

i. Staff shall confer with utilities and market participants and evaluate and report to the Commission whether utilities should be required to offer consolidated billing for CDG subscriptions, to improve the customer experience and reduce collections costs. This 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). The utility may be permitted to charge CDG providers for these services, creating a new revenue stream for the utility.

c. Customer maintenance costs:

i. Staff shall confer with utilities and market participants to and report to the Commission regarding what actions can be taken to provide efficient two-way electronic communication between CDG providers and utilities regarding subscriber lists and bill credit calculation and

application to customer bills to enhance customer experience and reduce customer management costs.

d. Interconnection costs:

i. Cost sharing: An initial, limited cost-sharing proposal was adopted by the Commission in Docket 16-01984 on January 24, 2017 that will apply to projects moving forward under the. A more robust cost sharing policy including the potential partial utility funding for upgrades is being considered in that proceeding. Recommendations will be presented to the Commission by the end of 2017.

ii. Cost containment: DPS Staff and NYSEERDA should work together to track interconnection upgrade costs throughout 2017, and thereafter provide the Commission with any recommendations that may be appropriate to address industry concerns about transparency and the alignment of costs with neighboring states, the Commission should take action to contain costs within reasonable bounds.

E. Utility Development of Virtual Generation Portfolios

1. Staff Proposal

The Staff Proposal recommends the Commission direct development by utilities of virtual generation portfolios through which they work with customers and DER providers so that DER are installed and operated in a way that best supports the overall system.

2. Comments

AEEI comment that the virtual generation portfolio concept closely resembles the role that the Distribution Service Providers are expected to serve. SolarCity supports the virtual generation portfolio concept, and comments that an initial set

of services should be detailed and filed by the utilities by July 1, 2017. SolarCity further suggests modeling on the existing Con Edison demonstration project.

3. Determination

As described above, we recognize that a performance requirement related to DRV and LSRV compensation presents risk and therefore adopt Staff's proposed fee-based portfolio service under which DER are aggregated into a virtual generation resource for the purpose of DRV. As directed above, utilities shall develop such options and have them available in time for our Summer 2017 implementation of the Value Stack.

F. Unbundling of Values

As described earlier under the discussion of DRV and LSRV, we require the utilities to file a work plan and timeline for developing locationally granular prices to reflect, as much as feasible, the complete value to their distribution systems from DER additions. This filing shall include a plan with milestones for the unbundling of those values and services embedded in rates. As noted previously, the identification of more precise valuation is essential to the implementation of REV and thereby providing value to the system and its customers. Moreover, the absence of that information results in the need to constrain DER and CDG deployment to limit bill impacts, when such information could demonstrate better methods of doing so. If a utility does not proceed with all appropriate speed to achieve such unbundling, the Commission may consider other strategies such as increasing the MW development limits in a utility territory while potentially disallowing the recovery of the impacts associated with the additional development as a means to mitigate bill impacts.

G. Coordination with DSIP and BCA Handbook Proceedings

The Commission recognizes the importance of coordinating the decisions and outcomes in this proceeding with those happening under other REV initiatives, in particular the DSIP and BCA Handbook proceedings. As described earlier, the VDER tariff initiative will complement these efforts to enable more precise pricing and valuation and the optimization of DERs.

The REV Framework Order began a transition from the historic model of a unidirectional electric system serving inelastic demand, to a dynamic model of a grid that encompasses both sides of the utility meter and relies increasingly on DER and dynamic load management.⁴⁸ To guide this transition of the utility model, the Commission defined a set of functions of the modern utility that are called, collectively, the Distributed System Platform (DSP). DSP functioning combines planning and operations with the enabling of markets. The vehicle by which improved planning and operations will be defined and implemented is DSIP.⁴⁹ The DSIPs contain (among other things) proposals for capital and operating expenditures to build and maintain DSP functions, as well as the system information needed by third-parties to plan for effective market participation.

As the DSP, utilities will play a leading role in animating markets by creating consistent platforms for the buying and selling of products and services among a broad set of market actors. Tools, processes, and protocols will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets.

⁴⁸ Case 14-M-0101, supra, REV Framework Order.

⁴⁹ Case 14-M-0101, supra, DSIP Guidance Order.

The information that the DSIPs provide is essential to the development of retail markets that accurately and fully price the value of DERs to the grid and electric consumers. The DSIP process is envisioned to be a multi-year plan, subject to public comment and regular updates. Accordingly, the DSIPs will document utility plans over a five-year period, with updated DSIP filings required every two years. The first formal updates to the DSIP filings will be June 30, 2018.

The Commission recognizes that many of the operating tools and functionalities required to incorporate and rely on large scale DER deployment to promote public policy outcomes, including the requisite algorithms and software solutions to price the marginal value of DER as efficiently as practicable, are either immature or incomplete and need to be developed. The DSIP filings include a high level plan to reveal potential distribution system values on a granular basis. Additionally, the plans identify specific areas in the utility footprint where DERs would provide benefits to the distribution system. However, in this order we require the filing of more detailed workplans and timelines for the development of locationally granular prices to reflect the full value to their distribution systems from DER additions. Therefore, as required above, within forty-five days of the effective date of this order, each utility shall file a work plan and timeline for developing granular locational prices to reflect the full value to their distribution systems from DER additions.

As the Commission recognized in the BCA Framework Order, the interests in sustaining a stable investment environment to support the DER market should be balanced with remaining flexible and adaptive so that the valuation process

does not become outdated or inaccurate.⁵⁰ Over time, developing more dynamic and granular methods will require a continuous process, rather than a single decision. The BCA Framework Order served as the first step in forming a robust and long-lasting BCA Framework.

The BCA Framework provides a means for evaluating DER alternatives as substitutions for traditional utility solutions, and against each other on a static basis. Additionally, the BCA Framework supports the development of tariffs that place a value on DER and in fact forms the basis of the Value Stack we are adopting in this order. Through these processes, the BCA Framework will be updated in coordination with the DSIPs.

H. Summary Calendar for Future Actions in VDER and Related Proceedings

a. March 2017

- i. Filing of utility tariffs implementing Phase One NEM
- ii. Staff initiates stakeholder engagement related to development of Implementation Order
- iii. Utilities file existing MCOS studies with workpapers

b. April 2017

- i. Utilities file work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions
- ii. Stakeholder process to develop implementation of recommendations continues
- iii. Staff issues DER Oversight Report
- iv. Staff initiates stakeholder engagement for BCA Handbooks

⁵⁰ Case 14-M-0101, supra, BCA Framework Order.

c. May 2017

i. Procedural Conference or other meeting to initiate VDER Phase Two

ii. Utilities file Implementation Proposals

d. Summer 2017

i. Commission consideration of recommendations related to VDER Implementation and DER Oversight

ii. Implementation of VDER Value Stack

iii. Commission consideration of actions to mitigate bill impacts and CDG project costs

iv. Staff issues CDG Low Income Proposal, including interzonal crediting proposal

v. Informal update to DSIPs filed by June 30, 2017, as required by March 2017 DSIP Order

e. Q4 2017 - Q1 2018

i. Commission consideration of any initial recommendations arising from VDER Phase Two process and review of utilities' plan and timeline on locationally granular pricing

f. Q3 2018

i. Formal update to DSIPs to be filed by June 30, 2018 per Commission DSIP Guidance Order

g. Q4 2018

i. Report and Recommendations for VDER Phase Two presented to Commission

h. Q4 2018 - Q1 2019

iii. Commission consideration of Report and Recommendations for VDER Phase Two

iv. Commission consideration of utility capital expenditure plans related to DSP functions and capabilities presented in rate case filings

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the Joint Utilities or the utilities) are directed to file, in conformance with the discussion in the body of this order and the below Ordering Clauses, tariff leaves implementing the transition from net energy metering (NEM) to a Value of Distributed Energy Resources (VDER) Phase One Tariff on not less than 5 days' notice to become effective on April 1, 2017.

2. Pursuant to Public Service Law (PSL) Section 66-j(3)(b), the Commission determines that it is in the public interest to set the limit for NEM under PSL §66-j in the territory of each utility, respectively, to a total rated generating capacity equal to the total rated generating capacity of generating equipment interconnected and served under PSL §66-j in that utility's territory as of the close of business on March 9, 2017 plus the total rated generating capacity of generating equipment for which Step 8 of the Standard Interconnection Requirements (SIR), for projects larger than 50 kW, or Step 4 of the SIR, for projects smaller than 50 kW, has been completed by the close of business on March 9, 2017. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017.

3. Furthermore, it is in the public interest for those limits to decrease as projects served under NEM PSL §66-j

are taken out of service to match the capacity of projects remaining in service. These decreasing ceilings should not be used to prevent customers served under PSL §66-j from repairing their system. The ceilings will not decrease below the 1% of 2005 electric demand level specified in PSL §66-j.

4. Each utility shall file a letter by March 16, 2017 recording the total rated generating capacity of interconnected projects served under PSL §66-j in its service territory as of the close of business on March 9, 2017.

5. Each of the utilities shall file a letter stating the final rated generating capacity of interconnected projects served under PSL §66-j, including projects that had completed Step 8 of the SIR for large projects or Step 4 of the SIR for small projects by March 9, 2017 and submitted notification of complete installation by March 17, 2017, by March 31, 2017, which will serve as the new ceiling for NEM for that territory.

6. The tariff leaves filed by each utility shall include amendments to the existing NEM provisions limiting eligibility for service under those provisions to projects that were interconnected and served under PSL §66-j in that utility's territory as of the close of business on March 9, 2017 and projects that had completed Step 8 SIR, for projects larger than 50 kW, or Step 4 of the SIR, for projects smaller than 50 kW, by the close of business on March 9, 2017 and provided written notification of complete installation by March 17, 2017 and to wind turbines interconnected under PSL §66-l before the 0.3% cap is for NEM under PSL §66-l is reached.

7. The tariff leaves filed by each utility shall include new provisions for Phase One NEM, which shall have the same eligibility rules as NEM under PSL §66-j, shall offer compensation using the same methodology as NEM, and shall apply the same policies except that Phase One NEM shall be limited to

a term of 20 years from generator interconnection and credits created under Phase One NEM will be carried over indefinitely, as described in this order, rather than being paid out at any time. The tariff leaves shall offer Phase One NEM to all mass market on-site projects, defined as projects interconnected behind the meter of a customer within a utility's residential or small commercial service class and not billed based on peak demand and not used to offset consumption at any other site, interconnected before the earlier of January 1, 2020 or a Commission order directing modification. The tariff leaves shall also offer Phase One NEM to large on-site projects, defined as projects interconnected behind the meter of a customer within a utility's non-residential demand-based or mandatory hourly pricing (MHP) service class and not used to offset consumption at any other site, and remote net energy metering projects for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, within 90 business days of the issuance of this order. The tariff leaves shall also offer Phase One NEM to community distributed generation projects that for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, within 90 business days of the issuance of this order and before the total rated generating capacity specified in Ordering Clause No. 9 has been reached. Wind turbines shall not be included in Phase One NEM until the 0.3% cap is for NEM under PSL §66-1 is reached.

8. The tariff leaves filed by each utility shall include provisions for Phase One NEM for remote net metered projects entitled to monetary crediting grandfathering under the April 17, 2015 Order Granting Rehearing in Part, Establishing Transition Plan, Making Other Findings in Cases 14-E-0151 and

14-E-0422 and interconnected after March 9, 2017, which shall offer compensation using the same methodology as NEM and shall apply the same policies except that Phase One NEM of grandfathered remote net metered projects shall be limited to a term of 25 years from generator interconnection.

9. The total rated generating capacity of Phase One NEM offered to community distributed generation projects in each utility shall be:

- a. For Central Hudson Gas & Electric Corporation, 39 MW;
- b. For Consolidated Edison Company of New York, Inc., 137 MW;
- c. For New York State Electric & Gas Corporation, 56 MW;
- d. For Niagara Mohawk Power Corporation d/b/a National Grid, 119 MW;
- e. For Orange and Rockland Utilities, Inc., 23 MW; and
- f. For Rochester Gas and Electric Corporation 28 MW.

10. The tariff leaves filed by each utility shall establish a two year grace period for carryover of credits by community distributed generation project sponsors consistent with the discussion in the body of this order.

11. Each utility shall file, within 7 days of the effective date of this order, the number of CDG projects and the MW of capacity represented by those projects that, at the time of this order, had already paid 25% of their interconnection costs, as well as the number of CDG projects and the MW of capacity represented by those projects that paid 25% of their interconnection costs between the issuance of the order and the filing of the letter. The utilities shall expeditiously develop

a method for providing real-time updates on the capacity left in each Tranche; until such a method is developed and implemented, each utility shall confer with Staff to determine the appropriate frequency of reporting based on local market conditions and shall file regular letters stating the current amount of capacity left in each Tranche based on those conditions. Each utility shall also immediately file a letter when any Tranche is filled.

12. Each utility shall file their most recent marginal cost of service (MCOS) studies and workpapers within 10 business days of the effective date of this order.

13. Within 45 days of the effective date of this order, each utility shall file a work plan and timeline for developing locationally granular prices to reflect the full value to their distribution systems from DER additions.

14. By May 1, 2017, each utility shall file an Implementation Proposal for public review and comment. The utility Implementation Proposals shall include, at a minimum, the items specified in the body of this order.

15. Department of Public Service Staff (Staff) shall file an updated whitepaper on oversight of Distributed Energy Resources within 30 days of the issuance of this order.

16. Staff shall work with the utilities and stakeholders to organize consultative meetings in advance of and, as necessary, following the issuance of the Implementation Proposals.

17. In consultation with stakeholders, Staff shall develop and file, by September 1, 2017, a Low-Income CDG Proposal, which shall include, at a minimum, information developed through the CDG Low Income Customer Collaborative, a report on the feasibility of an interzonal CDG credit program,

and discussion of the other options to encourage and support low-income customer participation discussed above.

18. Consistent with the discussion in the body of this order, the New York State Energy Research and Development Authority (NYSERDA) shall file new or revised Clean Energy Fund (CEF) investment chapters to support programs aimed to encourage and incentivize low-income customer participation in CDG projects, as well as to support the transition to the Value Stack.

19. NYSEDA shall operate the New York Generation Attribute Tracking System (NYGATS) and procurements consistent with the discussion in the Environmental Attributes Section of this order.

20. NYSEDA shall provide a report within 90 days of the issuance of this order detailing how the NYGATS platform can be used to generate information that will be used to support VDER Phase Two.

21. NYSEDA shall relinquish all rights to any environmental claims, certificates, attributes or other embodiments or memorializations of those claims for energy produced by any system to which it provided financial incentives under the Customer-Sited Tier and NY-Sun programs consistent with the discussion in the body of this order.

22. Staff is directed to work with NYSEDA, the utilities, and market participants to develop and file a proposal or proposals for steps that can be taken to reduce, eliminate, or mitigate market barriers.

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 No. 1 are waived.

24. The petition filed by SolarCity on October 21, 2016 is granted to the extent discussed in the body of this order and is otherwise denied.

25. 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.

26. These proceedings are continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

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

Commissioner Diane X. Burman, concurring:

As reflected in my comments made at the March 9, 2017 session, I concur on this item.

APPENDIX A. ESTIMATED MTCS

(to be replaced by utility compliance calculations)		All Averages are PV Load Weighted Averages						
	CHGE	O&R	NGRID	NYSEG	Con Ed	RG&E		
Estimated "Base Retail Rate"								
MFC	\$0.0042	\$0.0072	\$0.0021	\$0.0042	\$0.0051	\$0.0064		
SBC	\$0.0081	\$0.0045	\$0.0053	\$0.0061	\$0.0045	\$0.0068		
Deliv	\$0.0607	\$0.0785	\$0.0476	\$0.0368	\$0.1016	\$0.0379		
ICAP	\$0.0184	\$0.0288	\$0.0125	\$0.0114	\$0.0408	\$0.0121		
Energy+	\$0.0559	\$0.0608	\$0.0392	\$0.0488	\$0.0638	\$0.0447		
subtotal 1	\$0.1473	\$0.1798	\$0.1067	\$0.1073	\$0.2158	\$0.1079		
"Estimated Value Stack"								
E	\$0.0242	\$0.0242	\$0.0242	\$0.0242	\$0.0242	\$0.0242		
ICAP	\$0.0184	\$0.0288	\$0.0125	\$0.0114	\$0.0408	\$0.0121		
DA LBMP	\$0.0490	\$0.0489	\$0.0400	\$0.0400	\$0.0515	\$0.0365		
subtotal 2	\$0.0916	\$0.1020	\$0.0768	\$0.0757	\$0.1166	\$0.0728		
Estimated MTC (subtotal 1 - subtotal 2)	\$0.0558	\$0.0778	\$0.0299	\$0.0317	\$0.0993	\$0.0350		
VoD (estimated)	\$0.0063	\$0.0078	\$0.0084	\$0.0089	\$0.0316	\$0.0106		
Net Revenue Onsite Mass Market Impact	\$0.0737	\$0.0942	\$0.0457	\$0.0470	\$0.0919	\$0.0487		
Net Revenue CDG Impact*	\$0.0494	\$0.0700	\$0.0215	\$0.0228	\$0.0677	\$0.0244		
	* CDG impact < Onsite Mass Market impact due to E credit							

APPENDIX A CONT.						
Note: O&R and CE "Delivery" =						
PV load weighted avg. of						
tail block rates						
Note: NGRID's VoD offset is double the						
average VoD for all other upstate utility VoD						
estimates. Upstate average will be used						
instead for trancheing purposes						
	<u>CHGE</u>	<u>O&R</u>	<u>NGRID</u>	<u>NYSEG</u>	<u>Con Ed</u>	<u>RG&E</u>
Tranche 1 Compensation	\$0.1473	\$0.1798	\$0.1067	\$0.1073	\$0.2158	\$0.1079
times 0.95	\$0.1400	\$0.1708	\$0.1014	\$0.1020	\$0.2050	\$0.1025
times 0.90	\$0.1326	\$0.1618	\$0.0960	\$0.0966	\$0.1943	\$0.0971
MTC 1.00 (Tranche 1)	\$0.0558	\$0.0778	\$0.0299	\$0.0317	\$0.0993	\$0.0350
MTC 0.95 (Tranche 2)	\$0.0484	\$0.0688	\$0.0246	\$0.0263	\$0.0885	\$0.0297
MTC 0.90 (Tranche 3)	\$0.0410	\$0.0598	\$0.0192	\$0.0209	\$0.0777	\$0.0243
Rev Shift 1.00	\$0.0494	\$0.0700	\$0.0215	\$0.0228	\$0.0677	\$0.0244
Rev Shift 0.95	\$0.0421	\$0.0610	\$0.0162	\$0.0174	\$0.0569	\$0.0190
Rev Shift 0.90	\$0.0347	\$0.0520	\$0.0108	\$0.0120	\$0.0461	\$0.0136

APPENDIX B. SUMMARY TABLE OF DISTRIBUTED ENERGY RESOURCE CATEGORIES AND TREATMENT OF GENERATION ATTRIBUTES

		DER Category	Options	Is the project allowed to bid into RES Tier 1 Solicitations conducted by NYSERDA if otherwise eligible?	Will NYGATS create a transferable Certificate in the account of the generator?	Will NYGATS create a non-transferable Certificate in the account of the customer (indicates retirement by the customer)?	Do the attributes of the generation count towards the interconnecting LSE's RES Compliance Mandate?	Do the attributes of the generation count towards the Statewide 50% by 2030 renewable resources goal?
Pre-existing NEM Tariffs	Net Energy Metering	All Projects (Prior to Cut-Off)	RES Tier 1 (if eligible and awarded a contract by NYSERDA) *	Yes	Yes**	No	No	Yes
			Customer Retention	No	No	Yes	No	Yes
VDER Phase One Tariffs	Phase One NEM	On-Site Mass Market Projects and Small Wind Remote Net Metering Projects On-Site Large Projects	None	No	No	Yes	No	Yes
		Community Distributed Generation Projects	Interconnecting-LSE-Option	No	No	No	Yes	Yes
			Customer-Retention-Option	No	No	Yes	No	Yes
	Value Stack	On-Site Mass Market Projects and Small Wind (by opt-in, no longer net metering) Community Distributed Generation Projects (no longer net metering) Remote Customer Projects (no longer net metering) On-Site Large Projects (no longer net metering)	Interconnecting-LSE-Option	No	No	No	Yes	Yes
			Customer-Retention-Option	No	No	Yes	No	Yes

Note: The generation attributes of all renewable resource generation consumed by customers in New York State will contribute towards the Statewide 50% by 2030 renewable resources goal, which relies on both mandatory and voluntary contributions for its ends to be achieved. Voluntary market contributions do not count towards compliance with the Load Serving Entity mandates of the Renewable Energy Standard (RES).

* All pre-existing NEM projects that are eligible to bid into RES Tier 1 solicitations are subject to a previous RPS Main Tier contract rule that prohibited simultaneous collections of both New York RPS incentive payments and production-based incentives from any other state or local source, including CST, NY-Sun, and CEF program incentives.

** The Certificates will be transferable to NYSERDA pursuant to contract who may then transfer them to Load Serving Entities.

APPENDIX C. HISTORY OF NET METERING IN NEW YORK

In 1997, the Public Service Law (PSL) was amended to add §66-j, which provided net energy metering (NEM) for residential solar electric generation sized at no more than 10 kW.⁵¹ Over the following two decades, the PSL was expanded to include other forms of electric generating equipment, including farm waste, wind, micro-hydroelectric, fuel cell, and micro-combined heat and power systems along with other arrangements and project sizes, in particular to accommodate commercial customers.⁵²

Pursuant to statutory NEM provisions implemented through utility tariffs, customer-generators receive a bill from their electric utility based on their net energy consumption over the course of their billing period. For residential customer-generators and other customer-generators billed on a volumetric basis, each kWh of energy injected into the grid, when their generation exceeds their usage, provides an offset on their bill, equal to one kWh of energy, for when they draw energy from the grid during times when their usage exceeds their generation. Compensation for injected energy is therefore equal to the entire per kWh retail rate, including the portions of that rate that reflect supply charges, delivery charges, and other charges that are billed on a per kWh basis, such as taxes, the System Benefit Charge (SBC), and the Merchant Function Charge (MFC).

Demand-billed customers and mandatory hourly pricing (MHP) customers, a group generally made up of non-residential customers characterized by energy demand above a certain threshold established in each utility's tariff, are similarly

⁵¹ Laws of 1997 ch. 399 (effective August 13, 1997).

⁵² PSL §§66-j and 66-l. NEM of wind turbines is governed by PSL Section 66-l, while NEM of all other technologies is governed by PSL 66-j.

billed for net energy consumption with regard to the volumetric kWh portion of their monthly bill, which includes the supply charge and some other charges, including the SBC and MFC. However, because their delivery charge is based on their peak monthly kW demand, injections of energy do not reduce their delivery charge.

If a customer-generator's net energy consumption over the course of a billing period is negative, credits are carried over to the next month. Depending on the class of the customer-generator and the type of generation, the value of those credits is equal to either the per kWh retail rate or the utility's avoided cost rate, which is set based on the utility's cost for electric supply alone. Over the annual billing period, if a residential or farm non-residential customer-generator employing solar PV, wind, or anaerobic digester generation has negative net energy consumption, the utility issues a check for excess credits based on the utility's avoided costs. For other customer-generators and generation types, the credits continue to carry over into the next annual period.

In 2012, remote net metering (RNM) was authorized by the legislature and provided for a minor variation on the above formula. Specifically, a non-residential or farm-based residential customer-generator with a solar PV, wind, anaerobic digester, or micro-hydroelectric system may participate in RNM if it has two or more utility meters in the same utility territory and load zone.⁵³ A customer-generator participating in RNM may designate net metering credits created by an eligible generator at one property they own or lease (the Host Meter), to the meter or meters of other properties they own or lease (Satellite Meters). Some participants in RNM have minimal electric usage at their Host Meter and therefore inject almost

⁵³ PSL §§66-j(3)(e)-(h).

all of the energy generated into the grid to offset usage at the Satellite Meters; others have significant usage at the Host Meter and inject a smaller portion.

For most of the history of RNM, the value of credits was calculated by converting the kWh of excess generation at the Host Meter to monetary credits based on the per-kWh charges applicable to the Host Meter's service class. The bill for the Satellite Meter or Meters was then reduced by that monetary amount. This is often described as monetary crediting. In many cases, the per kWh charges at the Host Meter can be significantly larger than at the Satellite Meter because the Host Meter can be within a non-demand service class while the Satellite Meter can be within a demand-metered service class.

In order to avoid uneconomic arbitrage and unreasonable promotion of RNM over on-site net metering, the Commission modified the method of calculating the credit value.⁵⁴ Under the RNM volumetric crediting system adopted by the Commission, the excess kWhs generated at the Host Meter are transferred to the Satellite Meter as volumetric credits, which then offset the Satellite Meter's kWh charges and thereby reduce their bill. The Commission subsequently provided for the grandfathering under monetary crediting to permit existing RNM projects, and certain other RNM projects under development, to continue monetary crediting for 25 years.⁵⁵

⁵⁴ Cases 14-E-0151 et al., Petition of Hudson Valley Clean Energy, Inc. for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures (issued December 15, 2014).

⁵⁵ Cases 14-E-0151 et al., supra, Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings (April 17, 2015).

On July 17, 2015, the Commission issued an order instituting a Community Distributed Generation (Community DG or CDG) program (the Community DG Order) in response to the growing interest in access to DG from customers that, for a variety of reasons, could not participate in traditional NEM or RNM.⁵⁶ Like RNM, the Community DG rules permit credits to be accumulated through injections of energy from a generator installed behind a Host Meter. The credits may be either volumetric credits or monetary credits, depending on whether the Host Meter is served at non-demand rates or demand rates, respectively. Those credits are then distributed to members of Community DG project in order to offset the kWh charges at their meters. Among other requirements, Community DG projects must serve at least ten members and no more than 40% of the facility's kWh credit output must be distributed to large customers, defined in the order as customers with a demand above 25 kW.

The Community DG Order included several policies to promote participation in Community DG by low-income customers, including limiting participation in the six month initial phase to projects that either included a significant number of low-income customers or were located in an area where they would provide locational benefits to the utility and instituting a Low-Income Customer Collaborative. The Community DG Order also recognized the need for transition of DG compensation from NEM to a more accurate methodology, called in that order LMPD.⁵⁷ Staff was directed to promptly commence the development of a

⁵⁶ Case 15-E-0082, Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015).

⁵⁷ Representing of its combination of the value of energy based on locational marginal price (LMP) with other distribution (D) values.

report and recommendations on valuation of distribution system benefits provided by DER in consultation with stakeholders.

The Commission has repeatedly addressed the ceilings applicable to the amount of generation entitled to statutory NEM in each utility service territory.⁵⁸ In conformance with provisions of PSL §66-j that allow the Commission to increase the statutory ceiling caps if deemed to be in the public interest, in October 2012 and June 2013, the Commission issued orders in Cases 12-E-0343 and 12-E-0485, respectively, raising the ceilings to 3% of the Utilities' 2005 electric demand, three times the statutory cap of 1%.

Subsequently, on December 15, 2014, the Commission issued an order in Case 14-E-0151 setting the ceiling on the amount of NEM generation that the state's investor-owned electric utilities must interconnect to 6% of 2005 electric demand, 6 times the statutory cap. The Commission found in the December 2014 Order that a 6% ceiling was in the public interest because it was necessary to accommodate further DG development while methods of more accurately valuing DER were developed through REV and that a 6% ceiling would not impose unreasonable impacts on ratepayers.

⁵⁸ The ceilings discussed here, which appear in PSL §66-j, apply to all NEM-eligible generation technologies other than wind generation, which is governed by a separate provision, PSL §66-l. The terms and conditions of NEM under the two sections are essentially identical, except that wind is subject to a separately calculated statutory cap of 0.3% of 2005 electric demand for each utility, and therefore is not counted towards the cap that applies to all other technologies. The 0.3% cap has not been modified by the Commission and has not yet been reached in any service territory. For that reason, statutory NEM will continue to be available for wind turbines in each service territory until the 0.3% cap is reached; once the 0.3% cap has been reached in a utility's service territory, that utility should treat all NEM/VDER eligible generators, including wind turbines, identically.

In response to concerns that one or more utilities might reach the 6% ceiling prior to the implementation of a new DER compensation policy, in an order issued on October 16, 2015 in Case 15-E-0407, the Commission found that a floating ceiling, whereby utilities were required to accept all interconnection applications and to continue to interconnect NEM without measuring the DG capacity against an artificially set ceiling level, was appropriate and in the public interest for an interim period. However, the Commission explained that the floating ceilings would be applied until a more accurate DER valuation methodology was ready for implementation, at which point the ceilings would be automatically set "based on the PV and other DG generation that is actually installed in the service territory." The Commission recognized that the development of this more accurate methodology would require consideration both of the distribution system benefit issues discussed in the Community DG Order and of other costs and benefits associated with NEM and DER. The Commission directed the development of a report and recommendations by December 31, 2016, through a Staff-led collaborative process, presenting "more precise interim methods of valuing DER benefits and costs, as well as the appropriate rate designs and valuation mechanisms . . . , to serve as a bridge while the complete "value of D" tools and methodologies are developed."

In the context of the Commission's action in this Order to establish the critical and necessary foundation for transitioning to more accurate valuation and compensation for DER, it is useful to recognize that dozens of other jurisdictions have been wrestling with similar issues that we are addressing here. Whether prompted by regulatory or legislative initiative, over the past several years an increasing number of jurisdictions have been grappling with issues related to NEM and valuation of DER. Notably, the

motivations and objectives of other jurisdictions for addressing NEM compensation and value of DER are wide ranging, as are the outcomes and their respective progress.

Broadly speaking, actions taken in other jurisdictions to address these issues range from comprehensive assessments around valuation and optimization of DER, such as those in California⁵⁹ and our current undertakings here in New York, to rate design approaches explicitly impacting NEM compensation (e.g., mandatory time-of-use, increased fixed or customer charges), such as those in Arizona and Nevada. Approaches and initiatives have similarly ranged depending on the particular market segment being addressed, such as rooftop solar or off-site, CDG facilities and arrangements. In recent years, states including Massachusetts, Colorado and Minnesota have specifically taken actions related to their emerging CDG markets.

⁵⁹ CPUC, California's Distributed Energy Resources Action Plan: Aligning Vision and Action, November 2016.

Frequently, decisions and developments regarding these issues are often informed and aided by factual analysis or studies, whether directed by the decision-making body or put forth by an interested or active party. For instance, a recent report references upwards of 20 “value of solar” studies over the past several years.⁶⁰ New York’s deliberations have similarly been informed by preliminary analyses, the importance of which was recognized by the State legislature when they directed an analysis into the benefits and costs of NEM, completed in December of 2015.⁶¹

⁶⁰ Barbose, Galen L. Putting the Potential Rate Impacts of Distributed Solar into Context, January 2017. Lawrence Berkeley National Laboratory.

⁶¹ PSL § 66-n, resulting in Energy and Environmental Economics. The Benefits and Costs of Net Energy Metering in New York, December 2015. Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service.

APPENDIX D. SUMMARY OF COMMENTS

LISTING OF PARTIES THAT SUBMITTED COMMENTS

Acadia Center and Natural Resources Defense Council (Acadia)
Advanced Energy Economy Institute, Alliance for Clean Energy New
York, Inc, and the New England Clean Energy Council (AEEI)
Advanced Energy Management Alliance (AEMA)
Azure Mountain Power Company (AMP)
Bloom Energy Corporation (Bloom)
Borrego Solar Systems, Inc. (Borrego)
Center for Resource Solutions (CRS)
City of New York (CNY)
Coalition for Community Solar Access (CCSA)
Coalition of On-Site Renewable Users (CORE)
Cypress Creek Renewables (CCR)
Digital Energy Corp (DEC)
Distributed Sun LLC (DSun)
Energy Democracy Alliance (EDA)
Environmental Defense Fund and Institute for Policy Integrity at
NYU School of Law (EDF, NYU)
Grid Alternatives
IBEW, New York State Utility Labor Council, International
Brotherhood of Electrical Workers, Local Union 10 (IBEW)
Joint Utilities (JU) - Central Hudson Gas and Electric
Corporation, Consolidated Edison Company of New York, Inc.,
New York State Electric and Gas Corporation, Niagara Mohawk
Power Corporation, Orange and Rockland Utilities, Inc.,
Rochester Gas and Electric Corporation (JU)
Multiple Intervenors (MI)
National Fuel Cell Research Center (NFCRC)
National Fuel Gas Distribution Corporation (National Fuel)
New York Battery and Energy Storage Technology Consortium (NY
BEST)

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

New York City Environmental Justice Alliance, New York Lawyers
for the Public Interest (NYCEJA)

New York Solar Energy Industries Association (NYSEIA)

New York State Office of General Services (OGS)

New York Power Authority (NYPA)

Northeast Clean Heat and Power Initiative (NCHPI)

Nucor Steel Auburn, Inc. (Nucor)

NY Cow Power Coalition / Cayuga Marketing

Pace Energy and Climate Center (Pace)

Public Utility Law Project of New York, Inc. (PULP)

SolarCity Corporation (SolarCity)

Solar Parties (Solar Energy Industries Association & Vote Solar)

The Alliance for Solar Choice (TASC)

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

INITIAL COMMENTS

Acadia

Acadia strongly supports the overall framework recommended by the Staff Report for the Phase One methodology of (1) monetary net metering credits based on locational and temporal values applied to net hourly injections, (2) unlimited carryover of credits, and (3) cost allocation following the group of customers that benefits from the savings. Acadia also supports the key measures to make this transition a gradual one, including grandfathering for legacy projects and projects that qualify within 90 business days of the Phase One Order, "Tranche Zero" for CDG projects, and continuation of current net energy metering structures for mass market solar and small wind. Acadia generally supports the major elements of the Phase One crediting methodology, but has previously recommended a more stable and gradual approach and has concerns about the recommended values for delivery, particularly for projects that

do not qualify for the market transition credit. It is also crucial that key missing values are evaluated and addressed as soon as possible, including avoided transmission costs, and bill impacts due to reduced electricity and natural gas prices.

Acadia and NRDC

Acadia and NRDC offer general support for the overall framework and transition elements recommended in the Staff Report. With respect to the Phase One Compensation Methodology, Acadia and NRDC applaud the thoughtful approach taken in the Staff report which attempts to balance tradeoffs between efforts to accurately value distributed energy resources in a technology neutral manner, and the principles of simplicity and gradualism. Acadia and NRDC offer several recommendation which are intended to improve the Phase One Compensation Methodology. First, Acadia and NRDC support the proposed environmental value and MTC for CDG projects. Second, Acadia and NRDC, suggest that the recommendations with respect to avoided energy and capacity value are overly complex and provide uncertainty for customers and developers. With respect to installed capacity value, Acadia and NRDC recommend adoption of options that lean toward simplicity.

Next, Acadia and NRDC note that benefits associated with avoided transmission costs are not explicitly reflected in the value stack recommendations and recommend a full examination of transmission and sub-transmission value. With respect to distribution system value, Acadia and NRDC find the Staff proposal inadequate for projects that are not eligible for the MTC.

Acadia and NRDC also believe that the proposed methodology basing the demand reduction value across a service territory on the ten highest usage hours for the service territory and valued based on marginal cost of service studies

that will be updated over time is flawed because, among other reasons, the ten hour limit is arbitrary and ex-post evaluation does not give customers and generators a clear price signal when to act. Acadia and NRDC instead propose establishing a predictable delivery value credit that applies across a service territory, based upon a portion of the values shown in marginal cost of service studies for transmission and distribution. Finally, Acadia and NRDC oppose the recommended revenue impact cap and the proposed methodology for calculating such impacts. Acadia and NRDC support a 4% revenue impact cap as a more appropriate limit that will better facilitate achievement of the State's clean energy goals without posing an undue burden on utility customers.

AEEI

AEEI concerns surround the uneven treatment of different technologies and how BTM benefits of DERs are treated. AEEI cautions that the focus on solar should not detract from the central purpose of VDER to develop accurate pricing for DERs. AEEI encourages the Commission to incorporate flexible DERs, including stand-alone energy storage, clean dispatchable generation, demand response, and demand side management more broadly and more quickly. AEEI explains that these technologies had been receiving support from NYSEDA programs that were phased out with the expectation that a technology neutral LMP+D that included grid and societal benefits would compensate them, but the Phase One proposal leave a gap until the Phase Two inclusive compensation mechanism is developed.

AEEI advises that technologies eligible for the MTC will receive financing at a lower cost than projects that are ineligible for the MTC that will instead receive the demand reduction value. AEEI states that Phase One compensation fails to provide signals for demand reductions that can avoid the need

for future utility investments and does not differentiate between clean and conventional generation consumed behind the meter. AEEI argues this goes against established treatment of CES-eligible technologies that were previously able to sell RECs into the Main Tier of the RPS. AEEI urges the Commission to apply the DRV and LSRV to all BTM generation regardless of whether it is consumed behind the meter or exported. AEEI illustrates that a solar plus storage customer may receive a reduction in demand charges for dispatching its solar plus storage to meet system peaks, but only on the off chance that the customer's peak demand is coincident with system demand.

AEEI recommends expanding eligible technologies to those not included in PSL §§66-j and 66-l. AEEI encourages the Commission to set a timeline for adapting the Phase One compensation methodology to include standalone storage well in advance of the Phase Two methodology timeline.

AEEI advises that compensating only for net monthly exports does not accomplish the intended purpose, and as an alternative, the environmental compensation should be provided for the net output of the DER rather than the customer. AEEI notes that this recommendation requires the use of a separate meter, but says that BTM DER is likely to have separate metering for a variety of reasons. Furthermore, AEEI instructs that the full DER output should be separately metered to quantify and compensate the full benefits.

AEEI suggests that projects in service on the date of the Phase One Order should receive compensation under existing NEM rules for 25 years, rather than 20 years as proposed in the Staff Report. Additionally, AEEI believes the Commission should respect contracts with terms greater than 25 years that were signed prior to the Commission's Phase One Order.

AEEI argues that because of the way the market supply charge is calculated, customers that are not on mandatory hourly

pricing are likely to be inaccurately compensated for the capacity they provide to the wholesale market through the generation that they produce and consume behind the meter. AEEI requests clarification of whether compensation is based on net export during the hour or on MW performance, and recommends that it should be based on net exported generation. AEEI suggests technology-specific first year values be published to facilitate financing, and that capacity payments be allocated based on performance during the 460 summer hours.

AEEI advises that a methodology to convert the table of social cost of carbon costs into \$ per kWh price, since the EPA measures this in \$ per metric ton. AEEI believes the REC certificates associated with customer generation should either be counted toward the customer's sustainability certification or the CES goal, but not both. AEEI states that the Staff Report was not clear with respect to the relationship between the overall CES goal and the Tier One obligation, and requests more information. AEEI proposes that customers have the choice to forgo receiving the E value as part of the LMP+D stack, and instead receive title to fully tradable RECs for their eligible generation.

AEEI points out that the Staff Report leads to the conclusion that clean energy produced on behalf of CDG subscribers provides different environmental value than the same clean energy produced by individual customers where the energy is consumed onsite instead of being exported. AEEI suggests that all clean energy produced by DERs should be valued consistently and compensated at either Tier One rates or SCC rates. AEEI asserts that allowing non-exported energy to be used to reduce LSE obligations would result in the DER providing an economic benefit to the utility without receiving compensation, and amounts to double counting into the CES. AEEI complains that if on-site clean generation is claimed for

compliance in the manner proposed by Staff, a company's investment in clean energy will decrease the LSEs obligation to procure RECs, in effect transferring the benefit of a company's private investment in clean generation to the ratepayers of New York without compensation while eliminating the ability of that company to produce clean energy that is incremental to state targets.

AEEI advises that eliminating RECs for non-exported generation is a substantial departure from the previous RPS policy, and a change of this magnitude should have had greater stakeholder discussion. AEEI characterizes distribution costs as underrepresented because the proposed tariff neglected to include avoided losses. AEEI requests the Commission clarify that projects whose MTC is reduced to zero will receive the DRV.

AEEI recommends that parties be given sufficient time to review proposed values and the input calculations prior to Phase One tariffs going into effect. AEEI notes that the virtual generation portfolios seem very similar to the distributed system providers' role in the REV proceeding, and demonstrations are prudent.

AEEI prefers a revenue shift impact cap of 3% instead of the 2% cap in the Staff Report. AEEI suggests that the Commission should be prepared to adjust the tranche size if the market is not responding, particularly in utility service territories like NYSEG and RG&E, which have significant flexibility.

AEEI concludes by noting that Central Hudson and O&R are the most constrained by the Phase One proposal, and the Commission should establish a transparent process for managing interconnection queue management and SIR complaints.

AEMA

In its comments, AEMA expresses concern that different technologies will be compensated differently for providing similar, if not identical, services. AEMA comments that technologies that receive inferior compensation, but offer the same services, will be placed at a competitive disadvantage over the next two years while Phase Two is developed. In order to address this competitive disadvantage, AEMA proposes that the Commission: 1) Provide non-export demand response customers the option to lock in the 2017 dynamic load management program pricing in Con Edison's programs for 10 years; 2) include the environmental value that is available to NEM technologies to payments for the all dynamic load management programs prior to summer 2017; 3) limit the number of customers that can participate in the Phase One tariff until all technologies are compensated more equally; and, 4) act expeditiously to level the playing field and resolve all differences in compensation between technologies that provide similar grid services.

AMP

AMP supports NEM programs, but submits several concerns. AMP advises that the current RNM program requirement that a generator and off-take site be located in the same utility territory and load zone greatly restricts certain hydroelectric generators' participation. AMP explains that in some upstate areas the load zone and utility territory overlap is small, and it is hard for generators in these sparsely populated areas to find off-takers. AMP suggests that given the granularity of the value stack, it would be logical to lift the restriction that the two sites be within the same LBMP zone. AMP requests that if fully lifting the restriction is not feasible, the requirement be loosened for smaller load zones

such as Zone D, so that participation between contiguous zones or throughout the individual service territory be allowed.

AMP states that how the value stack elements will be calculated for existing facilities who may already be contributing to grid strength and reduce the cost of maintenance is unclear. AMP asks the Commission to consider how best to value the contributions of existing generators as well as new facilities, particularly with respect to calculating the LSRV.

AMP argues that it is vital for an existing renewable facility that enters into a DER agreement also be able to vest its RECs with the DER customer, and requests clarification that this will be permitted. AMP also seeks clarity regarding what effects this will have on the renewable baseline and/or the Tier One purchase obligations of the serving utility.

AMP claims that while hydroelectric generators operate at a far higher capacity factor than wind or solar, hydro generators are often at their lowest output during summer load peaks. AMP believes this may lead to unfair hydro compensation based on certain methods of calculating capacity value, and requests that the Commission consider this when determining how best to calculate the capacity portion of the value stack. AMP suggests calculating both a summer and winter peak may be equitable, and alternatively recommends considering the highest LBMP price as a supplementary peak measurement.

AMP urges the Commission to consider that new renewable resources should be intended to displace natural gas if GHG reduction goals are to be met. AMP advises that legacy hydro and natural gas are compensated at the same rates, and any negative impact of natural gas generators acts equally upon legacy hydro generators, which AMP claims are vulnerable to retirement.

Bloom Energy

Bloom Energy commends the Staff Proposal for proposing a workable solution and transition plan for moving from net metering to DER valuation. However, Bloom Energy believes that the Staff Report deviates from the goal of REV by restricting REV markets exclusively to net excess generation, by excluding behind the meter resources from traditional incentive programs before any REV market signals are in place. Bloom Energy urges the Commission to clarify that these exclusions will not be solidified in establishment of a methodology and process for determining the full value of DER for the larger purposes of developing DER compensation mechanisms built upon an LMP+D approach. Bloom Energy opposes the Staff Reports apparent recommendation that non-exporting behind the meter generation be effectively excluded from the CES. Bloom Energy comments that non-exporting, behind the meter generation creates multiple benefits including: 1) avoided or deferred distribution investments; 2) avoided distribution energy losses; 3) reduced wear and tear on the distribution system; 4) avoided environmental impacts associated with transmission and distribution facilities; 5) displacement of diesel generators; and, 6) enablement of grid isolating capabilities.

Borrego

Borrego is a member of the SEIA and the NYSEIA, and supports those organizations' comments, in addition to the following comments. Borrego supports Staff's proposal to grandfather RNM and CDG projects, but suggests several additions. Borrego expresses concerns with Staff's proposed capacity limitation on grandfathering CDG projects, and cautions against adopting an arbitrary cap. Borrego strongly recommends the Commission expressly state that the cap on grandfathering is justified because of the unique circumstances affecting the

present distributed solar market, but is not an appropriate precedent for future transitions. Borrego also requests the Commission order the access to each Tranche, including Tranche Zero, be based on the date on which each project makes its 25% interconnection payment. Borrego claims that older projects that are subject to the old SIR face a higher bar to achieve grandfathered status than more recent projects subject to the new SIR that only need to make 25% payment secure a position in Tranche Zero. Borrego requests the Commission specify that projects under the old SIR may make 25% payment within 30 days of the Commission Order allowing these projects to opt into the new SIR, and guarantee these older projects access to Tranche Zero.

Borrego advises that since a project's economics may hinge on successfully reserving a place in a particular Tranche, the Commission should direct the utilities to provide real-time information on progress toward the Tranches. Borrego believes the utilities should provide written confirmation of a project's Tranche assignment by the business-day after the project developer makes 25 % interconnection payment. Borrego proposes that the Commission direct utilities to release the number of MW that have been reserved in each Tranche in real time, as soon as practicable after the effective date of the Commission's order. Additionally, Borrego proposes that any projects that make 25% payment before this MW data is published automatically be placed in Tranche Zero, even if this placement exceeds Tranche Zero's size. Borrego favors a user-friendly interface, such as the NYSERDA MW Block Dashboard, to display each utility's progress towards each Tranche. Borrego explains that under the current proposal, key elements of the value stack will not be determined until after a Commission order. Borrego contends that the Commission should modify its CDG grandfathering proposal allow projects access to Tranche Zero until all elements of the

interim VDER tariff have been developed. Borrego maintains that unless the Commission identifies the DRV, LSRV, and Capacity values in its order, the Commission should specify that projects may qualify for Tranche Zero until those values are identified. Borrego explains that a workable interim tariff is strongly preferable, but if the Commission does not identify the methodology for calculating all elements in the value stack, it should extend the time period for grandfathering to well-beyond the 90-day period proposed by Staff.

Borrego generally supports the use of the zonal hourly LBMP as the energy component of the value stack, and notes that this this value should include all three components of the NYISO price - energy, congestion, and losses. Borrego requests the Commission clarify that projects under the interim VDER tariff will receive energy compensation equal to the full zonal LBMP price.

Borrego supports the use of the capacity element of the retail supply charge as the capacity component of the value stack. However, Borrego is concerned that Staff is proposing to leave the determination of which retail rate class to use for this calculation until the implementation phase, and recommends that the SC1 rate be used for the interim tariff. Borrego submits that the question of which service class load profile should be used for the capacity portion of the value stack is more appropriately resolved through Phase Two VDER tariff discussions. Borrego requests that Staff's alternative proposal for compensating projects for their capacity contribution during the 460 peak summer hours should not be adopted as the default approach for all DERs, but should be preserved for DERs that are able to design their systems to provide more capacity during the 460 peak summer hours.

Borrego believes the NYSEDA REC price is an acceptable default value for the environmental component (E) of

the interim value stack, but advises E should be revisited during Phase Two tariff discussions. Furthermore, Borrego states the E value and any other fixed values for CDG and non-CDG projects, should be determined at the time projects make their 25 % interconnection payment. Borrego strongly supports Staff's proposal to fix the E value for at least 20 years, and explains that a longer time is more appropriate because the NYSERDA REC value does not capture the full environmental value that DERs provide over time. To account for the increasing value DERs have on the state's GHG reduction goals over time, Borrego advises that projects under the interim VDER tariff should be allowed to opt into using annual values of the Social Cost of Carbon on a one-time basis. Borrego goes on that to facilitate this option, Staff should publish these values on a kWh basis for the full term of the DER tariff.

Borrego strongly supports including a market transition credit (MTC) for CDG projects, and recommends that the MTC be adopted for commercial and industrial (C&I) off-taker projects. Borrego explains that although revenues for C&I projects will likely increase slightly under the new tariff, the increase is unlikely to revive the "C&I market in New York that is currently dead." Borrego recommends the Commission use LBMP data from 2016, because comparing 2016 LBMP rates to 2016 residential NEM rates would provide the best comparison for determining the MTC. However, if the Commission decides to retain a multi-year average approach for projecting the LBMP, Borrego advises adopting a seven-year average, including 2016. Borrego notes that the Commission should use the same capacity value when calculating the MTC as the capacity value used for providing compensation under the interim tariff. Borrego further requests that the Commission calculate and announce the value of the MTC for each utility one time for all projects, including the stepped-down value in later Tranches.

Borrego proposes several clarifications to the VDER Staff Report, in order to set appropriate production curves to simulate DER generation over time. Borrego recommends that the MTC be calculated by reference to separate utility and NYISO zone-specific annual production models, with industry input. Borrego specifically requests the Commission assume that almost all projects will be roof-mounted in Con Edison's service territory, and that the Commission employ a production model that reflects this assumption; Borrego goes on to recommend specific assumptions for generating the production curves in other utility territories. Borrego states that the Commission should use a 2% annual escalator to the MTC to reflect the historical increase in retail rates over time in order to align compensation under the new tariff with market expectations and requirements.

Borrego supports including a DRV in the interim tariff, and suggests that the best interim solution is to base the DRV on the current, publicly available MCOS figures included in the Staff Report. Borrego states that each project's DRV value should be based on a 5-year, utility zone-wide rolling average of performance for similar DERs during the applicable peak hours. To address significant inter-annual variability in the peak demand hours' timing across utilities, Borrego says the Commission should modify Staff's proposal such that the DRV is based on a minimum of 25 hours per year.

Borrego strongly urges the Commission to adopt a proxy value for the interim locational distribution value for projects located in high-value areas, rather than leaving the locational value determination until implementation. Borrego continues that a more granular value should be developed in Phase Two.

Borrego concludes by expressing strong support for unbundling retail rates, developing a separate tariff for stand-

alone electricity storage systems, and applying these concepts to projects larger than 2 MW.

CCR

CCR supports the proposal that projects currently under development that pay 25% of their interconnection costs or execute an interconnection contract within 90 days of the Phase One Order should receive NEM compensation. However, CCR proposes extending the NEM compensation period for those projects from 20 to 25 years. CCR also proposes a similar extension of the Phase One tariff compensation period.

CCR recommends that, in order to reduce complexity, avoid the creation of unintentional inequities, and serve a compelling public purpose, the MTC should be set for consistency and transparency, and 100% of the production from a CDG facility should be granted the MTC in lieu of a DRV. Additionally, CCR proposes that recovery of the MTC should come from both residential and commercial service classes at a pre-defined ratio, and the step down between CDG tranches should be reduced from 10% to 5%. Further, CCR offers that a shorter, more relevant averaging time of 12 months for the energy value should be used in setting the MTC.

CCR comments that the cap for cumulative annual revenue impact from all projects under NEM continuation and the Phase One tariff should be set at 4% instead of the current 2%. CCR avers that a 4% Limited Net Revenue Impact more accurately balances the needs of gradualism with respect to regulatory changes, and is not likely to actually result in a 4% impact on ratepayers because Phase One value stack is likely underestimating the value of solar.

With respect to intermittent technologies, CCR supports the Staff Report's option #1 for deriving the capacity value from the retail supply rate, and proposes that the

capacity value be made more readily transparent. CCR also supports the proposed environmental value approach, and recommend that this value be fixed for the term of the compensation methodology. Next, CCR comments that that current approach for setting the DRV is likely to cause volatility and uncertainty and recommends adopting an alternative methodology which should be locked in for the duration of the compensation methodology.

Finally, CCR offers that there are several important logistical issues that should be addressed including: the creation of an online dashboard for tranche reservations and circuit breaker progress; a standard metric for tranche reservation; and, the requirement for key information including the details of the value to be communicated on customer bills.

CCSA

CCSA expresses concerns that without changes to certain provisions of the Phase One tariff proposal, the Staff Report does not provide for a robust CDG program that would create equitable access to local clean energy. CCSA argues that CDG should be prioritized for expansion, not targeted for curtailment.

According to CCSA, projects compensated with the Phase One tariff should be able to lock-in this compensation structure over the lifetime of the project. CCSA advises that a Phase One 4% utility net revenue impact would strike a better balance between utility impacts and providing meaningful opportunities for customers to install DG or participate in CDG. CDG projects that are sufficiently advanced in development to meet Tranche Zero criteria within 90 business days of the Order should be awarded capacity in that tranche, CCSA asserts. CCSA advises that the MTC should be applied to 100% of the generations from CDG projects, since the MTC encompasses benefit values not yet

quantified in Phase One. Further, CCSA believes the inputs to the MTC will need to be carefully calibrated to transition smoothly from Tranches One, Two, and Three. In order to accomplish this, CCSA advises that the tranche step downs should be no more than 5% increments, and a reservation system should be created with timely reporting of public data.

CCSA suggests that legacy projects in-service at the time of the issuance of the Phase One Order should receive compensation under existing NEM rules for the useful life of the system. CCSA explains that only two or three legacy projects will be in-service, and those project developers made investment decisions on these projects at a time when the standard term for net metering was life of system. Additionally, CCSA advises that solar project developers in New York have considered projects as 35-year investments, consistent with the estimated useful life of the system. CCSA says investment decisions were made under the assumption that the project could continue under net metering or a similar structure for as long as the system could operate. CCSA argues that Staff's basis for the 20-year term, Tier One REC contracts, should not dictate the term of the overall compensation. At the very least, CCSA requests the Commission include a clear statement that projects would move to a compensation structure other than simply defaulting to the wholesale energy market.

CCSA cautions that the most significant CDG development activity has occurred in the two utility territories with the smallest proposed tranche size for continuing NEM and the Phase One tariff, and Tranche Zero must be managed closely in these territories. In light of this, CCSA recommends that all projects meeting the proposed threshold requirements for Tranche Zero within 90 days of the Order be included in Tranche Zero.

The benefits associated with a stable and reliable revenue stream for project financing purposes outweigh the purported benefit associated with added precision in the determination of the capacity value contribution during specific peak hours, CCSA emphasizes in its support for Staff's recommendation to provide intermittent technologies per kWh compensation based on the utility's full service market supply charges.

CCSA states that the E value should be determined and set as a floor for the project, and the higher E value should apply if different than at the time of interconnection.

Regarding MTC calculation, CCSA notes that requiring each utility to complete final MTCs for each tranche may result in the utilities implementing the approved methodologies inconsistently given different utility interpretations. Therefore, CCSA recommends the Staff calculate the MTCs and tranches using utility data, transparently with input from all stakeholders. When it comes to tranching, CCSA suggests Staff implement a transparent communication platform to facilitate developer decision-making in order to ensure that tranche capacity is allocated in an orderly manner.

Finally, CCSA proposes that existing NEM projects that opt-in to the Phase One tariff in any tranche should not impact the availability of that tranche for new projects.

CORE

In its comments, CORE recommends that storage be treated like all other eligible renewable energy and be paid the value of "E," contrary to the proposal in the Staff Report. Core offers that paying Phase I pricing to energy storage facilities linked to on-site renewable energy projects will encourage such projects and further the state's clean energy goals.

CORE supports the proposed transition plan that grandfather existing projects based on their settled expectations at the time that they entered into their contractual and financial arrangements, but opposes the recommendation to limit grandfathering of NEM to 20 years. CORE recommends at a minimum, NME grandfathers should last for 25 years. CORE also opposes the proposed milestone requirements to be eligible for grandfathering as they would place eligibility for grandfathering within the hands of the interconnecting utility.

Next CORE proposes that the framework for the value of E should adhere to the BCA Order principles to ensure that on-site generators can make the renewable energy claims to which they are entitled. With respect to the primary categories of carbon and other air pollution emissions, CORE recommends that the Commission retain its approach adopted in the BCA Order, rather than adopt the Staff Report's proposed approach that would value E based on RECs. CORE also urges the Commission to clarify that on-site generators own the environmental attributes associated with their projects, including on-site renewable NEM projects. Further, CORE comments the on-site generators should retain title to RECs regardless of the receipt of the value of E, and that such values should be set based on proper analytical inputs without reference to RECs. Alternatively, CORE believes that on-site generators should be able to forego payment of E and receive fully tradable RECs.

With respect to CDG, CORE comments that the Commission should: 1) raise the 2MW cap to 5MW; 2) allow both the host commercial customer(s) and the subscribing mass market customers to retain their voluntary claims to the project's RECs; and, 3) not require the project developer to provide the interconnecting utility with competitive information regarding its subscribing customers and the allocation of project benefits. With respect

to billing, CORE recommends a strategy wherein credits from DER projects can be assigned to offset any related customer energy expense.

Next, CORE comments that the MTC should not be limited only to CDG projects because doing so inappropriately favors CDG at the expense on on-site projects. CORE proposes that the MTC should be made available to all commercial renewable projects.

Cow Power

Cow Power believes that ADG green power on dairy farms across the state should be valued to establish sustainability and incentivize the growth of on-farm ADGs throughout New York. Cow Power explains that electricity generated by ADG is cleaner and greener than energy produced by other renewable power sources because in addition to supplanting the negative attributes of fossil fuel generated electricity, anaerobic digestion directly improves air and water quality by treating manure storages. Cow Power points out that diverting inedible food waste to ADGs is an additional opportunity for the State to provide a rational and beneficial diversion of organic material from landfills.

Cow Power advises that an ADG capital investment must offer a predictable, amortizable rate of return in order to pass the long-run profitability and return on investment perspectives. Cow Power states existing ADG operators have significant, justifiable concerns regarding how the market for their energy will evolve and if reasonable long-term recompense will be earned for their investments of capital, labor, maintenance and operational costs, and opportunity costs. Cow Power cautions the current net metering program's valuation model does not provide a fair or sustainable valuation level. Cow Power explains on-farm ADGs have evolved to become significant base load power producers, which net substantial

amounts of energy to the grid. However, Cow Power elaborates, their demand based commercial service class relegates the value of the exported energy to the utility's avoided cost of generation rate, which is further reduced by non-representative demand charges. Cow Power argues that a farm's monthly demand charge is determined when the engine-generator set is briefly shut down for maintenance, which results in a disproportionately high demand charges. Additionally, Cow Power says that farms conduct scheduled engine-generator set maintenance when the overall utility demand is not being realized, resulting in farms with ADGs being over charged for demand in two ways. As a result, Cow Power advises that some generator sets are being taken out of operation because the major overhaul expense cannot be justified based on the net metering price of exported electricity.

Cow Power suggests using a value of E that reflects the actual value of ADGs would incent dairy farms with ADGs to increase biogas production, associated electric generation, and combined CO₂ equivalent reductions. Cow Power strongly disagrees with adopting different DER compensation policies for existing ADG operations and future operations, and cautions that future investment in ADGs by dairy farmers or outside investors should not be expected if visionary ADG pioneers are not compensated appropriately.

Cow Power recommends that the E component of the value stack include a value for the carbon equivalents destroyed as a function of electricity generation, and that other non-energy benefits be included in future proceedings. Furthermore, Cow Power includes an accurate way to value CO₂ equivalents destroyed through the process of generating power as Appendix B, and requests the value stack reflect this significant element of E as an adder at \$0.082 per kWh.

Cow Power submits that an MTC that closes the gap between the value stack and the retail market rate is appropriate for large on-site projects, which will receive a comparable price for energy valued under the value stack as they currently receive through NEM. Cow Power believes that a floating, market oriented pricing system is the best approach because project developers would have the benefit of increasing values of environmental benefits. Cow Power asserts the SCC is a more appropriate value of E for ADG technology than the REC value, as it would compensate technologies for their full impact on GHG reduction. However, Cow Power states a policy change that will allow legacy ADG RECs to be utilized in the E value stack. Cow Power claims that the benefit ADGs and other base load producers bring to the grid can and should be recognized within the calculation of the demand reduction value. Cow Power emphasizes that RNM should continue to be values at the retail consumer rate, and DERs should have the option of remaining under RNM or opting into the value stack. Cow Power states that depending on the DER, E, and time values, ADGs can be modified to provide dispatchable electricity, and ADG exports should have the option to be valued in a time of use system.

Cow Power concludes that ADG technology is unique, and it may be appropriate for the Commission to explore a separate rate class for ADG.

CRS

CRS strongly encourages the Commission to clearly differentiate between the CES voluntary market and the CES compliance market. CRS states that no portion of the value of the REC should be decoupled from contractual REC ownership. To avoid double-counting, CRS advises that if the tariff compensation transfers the environmental and other generation attributes to the LSE, the REC should also be transferred to the

LSE. Furthermore, CRS recommends that RECs be transferred to the state of the LSE when the state or LSE intends to use the renewable energy towards compliance with the CES.

CRS cautions against automatically counting renewable energy generation from DER towards CES compliance, by not requiring that LSE's own the RECs from this generation. CRS points out that a policy that automatically counts DER generation towards the CES erodes the benefits of DER to the on-site customer, is likely to reduce future investments in DER, and implicitly allows double counting of attributes.

CRS asserts that customers should be presented with clear choices regarding selling or transferring RECs, and fair compensation for the environmental attributes when the LSE receives the RECs. CRS continues that nothing precludes DER customers from selling RECs out-of-state for a voluntary purchase or for usage towards another state's compliance market. To avoid this double count, CRS recommends two choices for DER customers in the tariff: either allow the customer to provide regulatory surplus by the customer keeping the REC, or by the customers receiving appropriate compensation from the LSE; or, CRS suggests the DER customer should retain unequivocal ownership rights.

Digital

Digital requests that the full value of CHP be recognized and included at the earliest opportunity. Digital asserts that the Staff Report metering requirements are inadequate for providing high quality data about the performance of DERs. Digital argues that the meter costs should be recovered through the tariff and all DERs should be required to install these meters. Digital believes an exemption to the metering requirements may be appropriate for smaller nameplate capacity generation.

DSUN

DSUN comments address potential disruptors to the CDG market including RNM grandfathering, compensation terms, MTC compensation to projects with 100% retail subscriber base, and the variability in value stack component credits.

DSUN recommends extending the time RNM requirements have to make 25% Advance Payment from 90 business days to 150 business days following a Commission Order on VDER. Distributed Sun cautions that combining grandfathered RNM projects (Tranche Zero) and Tranche One into one Tranche sets an inordinately low capacity for projects. According to DSUN, the capacity limit on RNM is not based on cost recovery, but on Staff fears that grandfathering RNM would effectively prevent applying Phase One methodology in some or all utility service areas. DSUN claims that changing from NEM to the Phase One methodology will result in halting many projects and stranding significant developer investments in the state. DSUN suggests not counting Tranche Zero projects against the Tranche One capacity limit and only limiting RNM grandfathering by the 25% payment date within the Commission-established timeframe.

DSUN disagrees with migrating the compensation methodology from a consumer-focused tariff to a generation-focused tariff within such a short timeframe. DSUN claims that the precise value of energy and capacity in Phase One compensation presents significant challenges in projecting long-term revenues for a project. DSUN suggests that varying the MTC to mitigate the financial impact of changes in NEM compensation could provide greater certainty for Tranche One projects during the market transition. DSUN recommends the Commission set a floor price for the value of energy and the value of capacity equal to current rates when each project commits 25% advance interconnection payment.

DSUN advocates for extending NEM and Phase One projects' compensation term to 20 years. DSUN notes that other than the 25 year crediting methodology for NEM projects under the monetary crediting methodology, NEM-based projects in New York have not been subject to a term limit. DSUN advises that neighboring states do not impose do not impose term expiration limits for net-metering, and provide higher incentives and higher utility rates. DSUN cautions that limiting the net-metering term to 20 years while changing revenue streams on projects that have commenced development, would be unfair and cause huge uncertainties in the term of the revenue. DSUN requests the Commission clearly articulate a compensation methodology after the expiration of the compensation term.

DSUN concludes by advising that 100% MTC credit should be available to projects that certify a 100% residential subscriber mix. Distributed Sun believes this would provide a stronger business case to support including Low and Moderate-Income subscribers.

EDA

On behalf of 18 member organizations of EDA and 80 signatory allies, including elected officials, policy experts, small businesses, community-based organizations, and grassroots organizations, EDA submits concerns that Staff's proposal is likely to slow the development of much needed shared renewable energy, while creating anxiety and uncertainty in areas of renewable energy development not included in the initial transition. EDA respectfully insists that the transition away from NEM toward a VDER tariff include all the benefits and costs of renewables, not only those valued by utilities.

EDA advises that the Staff proposal is too complex given how little will change within the next two years in terms of real value paid to solar developers and solar customers. EDA

suggests that in light of the Community Solar NY Program, the Commission should avoid making it harder for people to be confident investing in solar, and simplify the policy so that there are only a few rules that can be quickly explained. EDA states that one important way to simplify would be to eliminate the 20-year timeframe proposed for the duration of a project's tariff, because providing compensation for only 20 years will leave a customer wondering what will happen for the remainder of the life of their system. EDA claims that four important benefits would be gained by allowing projects to choose between net metering and the Phase One tariff until the Phase Two tariff is developed, or for two years, whichever is greater. EDA advises that this would have a similar effect as the MTC Staff proposed, but is much simpler, would be in effect for a longer period of time, and would apply equally across utility regions. Furthermore, EDA recommends extending the option of net metering into Phase Two.

EDA maintains that the tranches combined with the flawed value stack Staff proposed would limit the new capacity of distributed energy that can be developed economically. EDA states that the predictability of renewable energy costs can make financing renewable energy projects easier, but that stability cannot be attained if the compensation mechanism for the value of solar is volatile. EDA recommends fixing the VDER tariff for the life of the system, like the Value of Solar in effect in Minnesota.

EDA believes VDER should result in improved solar access for all communities, and cautions against costly rules that favor large developers. EDA advises the Staff Report's Value Stack does not include all benefits of DERs, but excludes those benefits that most directly and immediately benefit communities. EDA states in both the BCA and Staff Report, those quantifiable benefits are left for the future. EDA recommends

VDER contain additional values for: reduced particulate air pollution, other contaminants, and toxins; reduced water use; EJ benefits; reduced energy burden for low-income people; local job creation; increased resiliency; and, ensuring geographical equity. EAD concludes by claiming that the Staff Report recommendations would throttle the transition to a decentralized energy system by placing caps on the number of shared renewable energy projects that could be economically viable any given time.

EDF/Policy Integrity

EDF/Policy Integrity appreciates the Staff Report and efforts to realize the REV vision by requiring DERs to be compensated for the full value they contribute to the grid. EDF/Policy Integrity advises that accurate compensation requires unbundled price signals that can value generation and transmission, distribution, ancillary services, as well as environmental benefits, separately, and that are granular with respect to time and location. EDF/Policy Integrity suggests the Commission lay out a clear roadmap to including environmental benefits not reflected in the current methodology, including air pollutants other than carbon and potential environmental value streams of energy storage. Furthermore, EDF/Policy Integrity advises that these environmental attribute valuations should be consistent across all Commission orders and technologies.

EDF/Policy Integrity cautions that the NYISO cost allocation for capacity and charges for ancillary services to LSEs is not aligned with cost causation, and is a hindrance to efficient DER compensation. EDF/Policy Integrity states that discussions with DER companies, the utilities, and the NYISO are needed to address issues that arise due to market design. EDF/Policy Integrity advises that the Phase One methodology

should establish a valuation and compensation foundation that can evolve as new knowledge and capabilities evolve.

EDF/Policy Integrity points out that using REC prices to value the environmental attributes of energy storage systems based on net exports is insufficient to estimate the full environmental value of currently eligible energy storage systems. EDF/Policy Integrity continues that the proposed methodology focuses only on net exports of energy storage that is paired with a clean generator, which cannot be used to accurately compensate energy storage systems for the environmental value they bring when they shift load from dirty to less dirty generation on the bulk system.

EDF/Policy Integrity supports Staff's proposal to move from volumetric crediting to monetary crediting based on locational and temporal values, and states that monetary crediting is necessary to reflect the dynamic nature of the values created by DER. EDF/Policy Integrity advises Staff's suggestion to keep NEM for small onsite DER that enters service before Jan. 1, 2020, is a simple solution. EDF/Policy Integrity also recommends using a MW trigger that would prompt new analysis and Commission consideration of appropriate action to avoid potential negative consequences if DER penetration accelerates. In contrast, EDF/Policy Integrity advises that for distributed generation that is not co-located with load, the more time- and location-granular approach away from traditional net metering should occur more quickly. EDF/Policy Integrity explains that any locational benefit associated with these systems cannot be expected to offset any system needs created by the customer's usage, which undermines a key rationale for treating NEM as a reasonable first-order estimate of the value of DER that are co-located with load. EDF/Policy Integrity believes that Staff's proposal to subject CDG and RNM to the Phase One methodology from the outset makes sense, and submits

that large scale onsite projects are also worth the investment in advanced metering and should therefore also be put on the Phase One methodology.

EDF/Policy Integrity strongly supports Staff's recommendation to use a bottom up value stack approach for the Phase One methodology. EDF/Policy Integrity also supports Staff's suggestion of using LBMP as the energy value.

EDF/Policy Integrity agrees that using the proposed installed capacity value approach is reasonable because it is consistent with NYISO's current approach for allocating the cost of installed capacity to the various utilities. EDF/Policy Integrity notes that the second of Staff's two proposed crediting alternatives for intermittent technologies is better aligned with underlying system costs and would encourage efficient project siting and avoid future costly capacity investments. EDF/Policy Integrity encourages the Commission to adopt Staff's second approach. Additionally, EDF/Policy Integrity recommends that if Staff's discussions with the NYISO result in an ICAP cost allocation approach that is more aligned with cost causation, the crediting approach for ICAP under the Phase One methodology should be updated.

EDF/Policy Integrity agrees with Staff that the SCC should be the floor price of the E component, but recommends that environmental attributes of reduced SO₂ and NO_x emissions should be added to the value stack. EDF/Policy Integrity recognizes that using the Tier One REC price is practical, but highlights that the REC prices could be substantially different from the actual damage costs of carbon emissions depending on the market outcomes. Moreover, EDF/Policy Integrity points out, using a REC price to distinguish between the environmental value of generation from emitting vs. non-emitting DERs will be unhelpful. Therefore, EDF/Policy Integrity encourages the

Commission to adopt a methodological framework that can be used for all resources consistently.

EDF/Policy Integrity supports developing a demand reduction value and locational system relief value. However, EDF/Policy Integrity stresses the importance of making the value of D and the associated credits as granular as possible with respect to both time and location.

EDF/Policy Integrity emphasizes that implicitly incorporating the D value of CDG projects in the MTC as Staff suggests does not provide sufficient incentives for locating and designing projects to provide high value to the distribution system. EDF/Policy Integrity proposes making part of the MTC conditional on project performance during some number of the highest usage hours in a particular distribution network or circuit. Alternatively, EDF/Policy Integrity suggests making a higher Demand Reduction value part of the criteria for qualifying for higher value tranches of the MTC. EDF/Policy Integrity supports Staff's suggestion that the utilities should offer fee-based portfolio service for intermittent renewables to provide compensation stability and reduce risk, but maintains that fees charged for such a service must be just and reasonable and have regulatory oversight.

EDF/Policy Integrity notes that LIM issues were not brought up during collaborative discussions or mentioned in Staff's Report. EDF/Policy Integrity advises that LMI participation in CDG is important but poses challenges, and recommends additional incentives for developers that enroll LMI customers as part of CDG projects. EDF/Policy Integrity describes one approach as a greater MTC for CDG projects that have a significant share of LMI subscribers.

EDF/Policy Integrity concludes by agreeing that gradualism is important, but cautions that if an MTC is also designed capture some of the values currently un-monetized in

the value stack, using the full value of the revenue impact of an MTC as a limiting mechanism may be inefficiently restrictive.

GRID

GRID requests that benefits to LMI communities be included in the valuation of solar for CDG. GRID advises that a predictable, long-term CDG rate is essential to LMI participation, and requests Staff integrate a LMI valuation of solar into the calculation some way so that the LMI customer base is prioritized. GRID claims that New York is a difficult market low-income solar because the state has lower differential incentives for low-income solar than other markets. GRID advocates for preserving full retail NEM credit for CDG projects that can demonstrate meaningful savings for LMI participants; alternatively, GRID promotes ensuring an added, external incentive, or other market signal to deliver meaningful savings through low-income CDG.

JU

The JU express support for the expansion of customer choice and the growth of DER, but recognize that not all DERs provide the same benefits and comments that it is essential to develop a policy that will set the stage for future economically-efficient development of DER, and to be able to differentiate the value of differing DER characteristics. Along those lines, the JU offers strong support for the reforming and or replacement of NEM.

The JU support the Staff Report's goals of limiting annual bill impacts to 2%, compensating DER based on the benefits it provides, and providing a fair and appropriate transition to more sustainable compensation levels using a modified tranche structure. On the other hand, the JU opposes the assumptions in the Staff Report that would result in levels

of DER growth that cannot be sustained within a two percent customer bill impact, but instead would result in annual total bill increases of up to 25% in some utility service territories. The JU also notes that the Staff Report would improperly provide compensation to all projects, irrespective of whether the project attributes are valuable to deferring generation or distribution system investments and, would in some cases, lock in these DER payments at levels greater than the current NEM construct for 20 years, thereby shifting significant risks and costs to electric customers for decades to come. The JU believe that the customer Staff Report likely understated the customer bill impacts to be expected and cites a number of inaccuracies and mistaken assumptions in the Staff report, to which the JU provides corrections. The JU propose that existing data be updated with more accurate information to create a transition formula that will better approximate and limit incremental customer bill increases.

With respect to the 2% cap on customer bills, the JU proposes that the Commission also establish a more robust circuit breaker mechanism that monitors actual bill increases on a quarterly basis and will initiate immediate and predetermined actions (instead of mere Commission review) if that cap is projected to be reached. The JU comment that this approach would provide both visibility and certainty to the market, allowing developers foresight into the growth of the market and allowing them to plan their businesses accordingly. Additionally, the JU recommend that the grandfathering period for new and existing mass market residential and small commercial DER be shortened from the 20 years proposed in the Staff Report to 15 years in order to reduce costs and long-term risks to all customers and provide for a more effective transition to a more granular Phase Two valuation methodology.

With respect to wholesale ICAP payments and value, The JU propose using an actual ICAP valuation that will encourage peak demand reduction as opposed to the Staff Reports proposed volumetric usage-based ICAP credit that will reward projects that can reduce peak demand, and will increase customer bills without any commensurate benefit. The JU also propose that energy and ICAP payments should be recovered on the supply side of the bill instead of being included as part of the energy delivery charge.

With respect to the value of DER to the distribution system, the JU suggests that instead of using NYISO wholesale system peak coincidence as an estimate for distribution coincidence, location-based compensation should be utilized. The JU propose that both positive and negative LSRVs be developed based on the identification of high-value locations, which would be an additional value or a reduction in value on top of the MTC compensation for all projects based on the location of the project and the corresponding distribution benefit detailed within each utility's MCOS study.

Next, the JU notes that the Staff Report assumes that DER distribution value will result in near-term avoided costs for utility customers. However, the JU comments that due to the long lead time required to plan and install distribution infrastructure, these benefits will phase in over time, leading to a reduction in the near-term avoided costs and therefore to larger near-term bill increases without commensurate benefits. The JU also suggest using the same values for energy and capacity in both the retail rate and the value stack calculations to avoid understating or overstating of actual energy and capacity market prices, which may result from using the snapshot of current retail rates which includes utility hedges.

Turning to the tranche structure, the JU proposes that DER compensation levels be stepped-down in even increments over five tranches instead of three. Additionally, the JU propose to allocate the budget dollars evenly across all tranches, rather than concentrating 60 percent of the budget in the most expensive tranche, so that more resources can be built for the same customer dollars. The JU also suggest establishing an upper limit on the total MW of CDG that can be installed under Phase One in order to recognize operational limits and allow room for industry development following the conclusion of Phase One.

The JU recommend avoiding increasing compensation above current NEM rates unless the DER's value to the electric system warrants such compensation. The JU comment that the compensation level provided for in the Staff Report is not necessary to achieve the State's policy goals of bringing more CDG to New York, and will lead to fewer clean energy resources being built for the same customer dollars. Additionally, the JU notes that, in addition to overcompensating CDG, the Staff Report increases compensation over current levels by assuming that 80% of subscribers are residential, and therefore eligible for the MTC, when it is more likely that only 60% of subscribers would be residential customers. The JU also propose to include a reasonable limit on CDG development in any utility's service territory to account for operational limits that will be reached with high penetration of solar resources. The JU recommends limiting the total incremental distributed solar load in a utility's service territory to 5% of peak load. According to the JU, such a limit would allow the DSP to develop and provide price signals to competing technologies (such as demand response, energy storage, and other forms of clean generation) that may provide similar or identical beneficial attributes. The JU support the recommendation to require projects to have

paid 25% of the interconnection costs determined by the utility, or to have signed an interconnection agreement in the event that no such costs exist, within 90 days of the Order to receive Tranche Zero designation.

Turning to the MTC, the JU proposes that the period over which the MTC is paid should be shortened to 10 years, with a proxy for distribution benefits set for 5 years, to limit the long-term shifting of risk from developers to customers. The JU also recommends that a portion of the MTC be performance-based to encourage DER to align their output with electric distribution system needs. Doing so, the JU comment, would create a price signal for DER and could be achieved by using Staff's concept of weighting actual production at the time of the 10 highest distribution load hours.

Finally, with respect to cost recovery, the JU comments that several key questions remain unanswered, the answers to which will have a significant effect on the actual bill increases that any given customer class experiences. As an example, the JU comment that allocating energy and capacity payments to DER only to those customers within the service class of the DER customer may result in undue impacts to residential and small business customers, when the benefits from that energy and capacity may actually benefit all customers.

The JU also note that the Staff Report will lead to new implementation costs, including improved metering to implement hourly energy payments and billing system modifications, which will need to be carefully considered so that costs are properly assigned to those benefited by them. In addition, the JU points out several mechanical issues with collection of costs as accounting and cost allocation practices vary among Utilities and will require further focus as the quantity of these resources grows on the system. The JU propose that the monetary credits should be allocated on a percentage

basis, based on the MWhs generated by the project each month in order to provide transparency for the CDG subscriber and provide a link to any future service class cost allocations and allow potential CDG subscribers to compare prices between competing CDG projects and provide a better comparison to their existing utility bill.

MI

MI comments that the Staff report seems to have a conflict between a desire to accurately price DERs and promoting DER penetration. MI recommends that it is of the utmost importance that valuation of pricing of DER be accurate and precise. MI supports the cost-effective development of DERs and cautions that overvaluing DERs can lead to uneconomic choices, misallocated resources, and higher customer rates. MI advocates that DERs be facilitated, and barriers be addressed, but that the Commission refrain from utilizing the valuation process as a means to subsidize DER developers and/or owners at customer expense.

MI proposes that, as a way to address the barrier that mass market delivery rates are not sufficiently granular to facilitate DER investment, the focus should be on implementing accurate delivery rates and DER values, and not on the subsidization of DER developers and/or owners to overcome this barrier. MI also comments that the Staff Report focuses on the benefits of DERs, but does not explore the costs associated with increased DER penetration, such as increasing demand on certain ancillary services. With respect to timing, MI disagrees with the proposal to begin Phase Two immediately after the development of Phase One methodology and suggests waiting so that all parties, can benefit from Commission guidance in resolving issues pertaining to the interim methodology prior to beginning work on a longer-term valuation methodology.

With respect to energy storage, MI comments that: 1) energy storage should be evaluated on its own merits and the value that it provides should be calculated accurately and applied where utilized; 2) the addition of energy storage, in and of itself, should not warrant disparate treatment among otherwise comparable DER projects; and, 3) energy storage provides another example of the need for an accurate pricing methodology for DERs.

Next, MI opposes that recommendation that projects entitled to receive NEM may elect to opt-in for compensation under the Phase One methodology. MI argues that allowing project to elect to switch is a "lose-lose" proposition for non-participating customers because it will allow a project to elect to utilize which ever valuation methodology is more lucrative, instead of keeping the project on NEM; the methodology that the project had a reasonable expectation that they would continue to receive.

With respect to cost allocation, MI urges that cost allocation be determined in accordance with cost causation principles and recognizes that the Staff Report generally appears to be consistent with this approach, but that additional clarity is needed. MI supports the recommendation that compensation for energy and capacity values be recovered from the same customers that benefit from reduced utility purchases of energy and capacity so long as this principle means that when DER project reduces the amount of capacity that a utility is obligated to procure, the beneficiaries of such reduction are the utility's commodity customers and not large, nonresidential retail access customers who have their capacity obligations set based on their peak loads, or capacity tags, and do not benefit similarly. MI also concurs, strongly, with the recommendation that compensation for environmental values be recovered from the same customers that benefit from reduced utility purchases of

Tier One RECs because if compensation for environmental values were recovered from all customers, retail access customers would be double-charged; once for DER compensation to reduce utility REC obligations and a second time to cover their own ESCO's REC obligations. MI also strongly concurs with the recommendation that:

For demand reduction and locational system relief values, utilities should identify what portion of the value results from avoided lower voltage level costs and what portion results from higher voltage level costs. The portion of compensation reflecting avoided lower voltage level costs will be recovered from all lower voltage level delivery customers. The portion of compensation reflecting avoided higher voltage level costs will be recovered from all delivery customers.

MI agrees that the recommendation that MTC compensation be recovered from the service class of the project subscribers for CDG, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class, is consistent with cost causation principles. However, MI opposes the use of a MTC because it believes that the MTC represents an economic subsidy in excess of the actual and calculated value provided by DERs.

With respect to revenue impacts, MI expresses concern with respect to the recommendation that a 2% upper bound be placed on the revenue impacts for all projects interconnected after the date of the Phase One Order. MI comments that: 1) this 2% figure appears to apply to annual revenues, while MI proposes that utility delivery revenues would be more appropriate in this context; 2) limiting application to projects interconnected after the date of the Phase One Order ignores the impacts of NEM projects implemented prior to that date; 3) it is not clear whether the 2% figure was deemed "reasonable" in vacuum, or in the context of the myriad of other Commission-

approved initiatives that are placing upward pressure on rates and prices; and, 4) the 2% figure appears to have little practical meaning because hitting that threshold apparently would not result in the cessation of additional customer impacts or even a meaningful reduction in prospective compensation.

MI also expresses concern with the recommendation that new DER projects retain the compensation methodology in effect at the time they are put into service for 20 years after their in-service date. Such a term, MI avows, will make customers responsible for excess payments for potentially 18 years if a more precise and accurate valuation methodology is developed and approved approximately two years after the Phase One order is issued, and results in less total compensation for some or all DER projects implemented under that order. On the other hand, MI comments that if a 20-year term is adopted, DERs should not also be afforded to opportunity to opt-in for compensation under the new tariffs or mechanisms developed in Phase Two.

Next, MI disagrees with the recommendation that the receipt of other incentives (including incentives offered by NYSERDA and federal and state tax incentives) not impact their eligibility for or compensation under NEM or the Phase One tariff. MI comment's that to do so would be wrongfully compensating those projects twice for the exact same attributes. MI recommends that DER projects already receiving RPS incentives or subsidies be declared ineligible for any environmental adder based on the SCC or Tier One REC price because such additional compensation would be duplicative.

MI opposes extending the availability of NEM based on the current compensation methodology to all mass market and small wind projects interconnected after the issuance of the Phase One Order and before January 1, 2020. MI contends that extending NEM to DER projects that have yet to be developed and

which may not be interconnected until 2019, carries the concept of grandfathering too far.

With respect to installed capacity value, MI opposes the recommendation that intermittent technologies will receive the per kWh compensation based on the capacity portion of the utility's full service market supply charges and claims that this approach makes no sense, is not based on a DER project's actual performance, and serves merely to subsidize DER developers and/or owners at the expense of customers. MI proposes that all DERs should be compensated for ICAP based on their actual performance, without customer-funded subsidies.

With respect to valuing environmental benefits, MI comments that the proposals on this issue serve primarily to subsidize DERs at the expense of customers and thus fail to accurately value DERs. MI offers that the Tier One REC price is reflective of economic subsidies, not environmental costs or benefits and, as such, should not be utilized in any DER valuation methodology that is striving for accuracy.

Next, MI comments that intermittent DERs should not be paid the Demand Reduction Value because they cannot respond to calls to reduce demand during system peak periods and, therefore, do not provide comparable benefits. MI reiterated that DERs should be compensated based on actual performance. MI also opposes the recommendation that Locational System Relief values be calculated and then fixed for ten years because this could subject customers to increased risks and costs, and may overcompensate DERs. Instead, MI proposes that such values should be adjusted annually based on utilities' actual costs. Furthermore, MI comments that DERs should not be afforded the option to select between Demand Reduction Value and MTC. According to MI doing so places excessive emphasis on DERs concerns and not enough on customer concerns and effectively

allows the DERs to choose the option that benefits it the most and thus maximizing customer payments and rate impacts.

MI also expresses concern with the recommendation that the Phase One Order not apply to any on-site mass market projects because the maturation of the segment and business models requires notice and a more gradual evolution to a new compensation methodology. MI comments that this assertion is not bolstered any explicit analysis or supporting facts and ignores the considerable notice provided previously regarding this proceeding. MI maintains that this exclusion for mass market DER projects benefits mass market customers only at the expense of other customer classes.

MI agrees with the recommendations that remote net metering projects, on-site large projects, and CDG projects placed into service after issuance of the Phase One Order and not eligible for continuation of NEM be subject to the Phase One Order valuation methodology, provided that the outcome of this proceeding is the development of a valuation methodology that truly is accurate and not one that unduly subsidizes this type of DER project at the expense of customers.

Finally, with respect to framing the analysis, MI recommends that the Commission focus on the total delivery rate impacts associated with its NEM-related policies, as well as with its future rulings herein because this would provide more useful information about the likely delivery rate impacts that have been borne by customers. MI also comments that the Commission should refrain from evaluating such customer rate impacts in a vacuum as there are numerous other initiatives already in effect that are placing upward pressure on delivery rates.

NECHPI

NECHPI supports the inclusion of micro CHP (less than 10 Kw) in Phase One of the proceedings, but comments that there is very little activity surrounding micro CHP in the market, and since CHP greater than 10 KW have been omitted from phase One, CHP is essentially ignored in these proceedings. Accordingly, NECHPI offers the following recommendations: 1) CHP greater than 10 KW should be allowed to opt-in for compensation under Phase One methodology; 2) the recommendations for cost allocation should be made applicable to CHP greater than 10 KW; 3) CHP Projects greater than 10 KW should be allowed to retain the compensation methodology in effect at the time they are put into service for 20 years after their in-service date. After the period ends, the projects should still be compensated based on the tariff than in effect; 4) the compensation methodology should be determined at the time it pays 25% of the interconnection costs or at the time of execution of SIR contract, if no such payment is required; 5) the value and the compensation for the energy the eligible generation facilities inject into the system, and the reduction in the energy utility purchases because of the injection should take the form of actual day ahead NYISO hourly LBMP energy prices at the time of generation; 6) CHP technologies that opt in after installing storage, should be compensated each month with a lump sum equal to their MW performance during their peak hour in the previous year multiplied by the actual monthly generation capacity from NYISO's ICAP market; 7) separate method for determining the compensation for the demand reduction value that is created by CHP greater than 10 KW keeping in mind the unique characteristics of a CHP system. Alternately, the methodology that is currently proposed for intermittent technologies and dispatch able technologies should be extended to CHP systems greater than 10 KW; 8) in order to recognize locational system

relief values, a dollar per Kw-year compensation should be identified for those areas to reflect higher value; 9) market transition credit should be made available to CHP projects greater than 10 KW and should be made available in tranches; 10) for calculating the MTC that must be made available in each tranche, no number representing the Demand Creation Value (DRV) should be included in the value stack for the purposes of this calculation as the purpose of MTC is to subsume the value DRV represents; and, 11) in those utility areas, where the tranches are zero or negative, there should be no tranches and instead, the previous tranches should be larger.

Additionally, NECHPI proposes that the capacity payment should not be linked to the single hour performance, when the weather is known only after the fact because doing so may create a disincentive toward storage and prevent the development of hybrid systems. Finally, NECHPI comments that there should be a time limit on carrying over credits month-to-month because to do otherwise would likely create likely a bias against large systems.

NFCRC

NFCRC advises that BTM technologies, like fuel cells, are an essential component of a truly distributed grid and should be fully and fairly valued in both the interim and long-term methodologies for valuing DER. NFCRC argues that the current order of events does not support the intention of an uninterrupted transition to a Phase One tariff. NFCRC expresses concern that fuel cells will be adversely affected in the critical time between the traditional incentives and the REV market signals, when projects that have already secured financing may be deterred.

NFCRC states there are several features of the Staff Report that do not provide adequate certainty and/or incentive

to promote non-solar technology development. NFCRC asserts that while the Staff Report is required to take into account existing legislation such as PSL §§66-j and 66-l, the Staff Report runs counter to a core REV tenant for neutrality and fuel and resource diversity.

NFCRC claims the year-to-year variability in MCOS creates uncertainty that will hinder project development and investment, since the demand reduction value compensation of on-site large projects would be derived from each utility's MCOS. NFCRC points out that contrary to technology neutrality, solar technologies such as CDG and mass market will be afforded revenue stream predictability in Phase One. NFCRC believes calculating the compensation for the ICAP value from dispatchable technologies using the NYISO ICAP spot price will expose investors to spot price volatility.

NFCRC seeks clarification on which "MW performance" will be used for the installed capacity value. NFCRC requests the Commission clarify that "MW performance" is in fact the installed capacity of the generating asset and not the net MW exported to the grid.

NFCRC reiterates the eligibility requirements and compensation rates for VDER should include BTM, as well as utility side resources. NFCRC continues that there is additional value delivered to the grid that is not addressed in the Staff Report. NFCRC illustrates that all of the values described in the BCA are met by BTM technologies, yet there will be no capacity signal or environmental signal in rates in the interim period. NFCRC explains that the lack of clarity regarding ownership of environmental attributes should be in the Phase One report to avoid a significant shortcoming and future inconsistency. NFCRC recommends Phase One mimic the recent policy movements of ISO-New England, PJM, and FERC and compensate generators for the full value of BTM resources.

NFCRC suggests a MTC for on-site large projects in lieu of the uncertain environmental attribute ownership approach. NFCRC says on-site large projects should have an irreversible opt-out option. Furthermore, NFCRC believes it is vital important that all project development receive an equal level of certainty, regardless of technology.

NFCRC claims there is inconsistency since the Commission originally included non-exported BTM generation as an eligible Tier One REC, but the Staff Report indicates there is not Tier One REC for separate sale. NFCRC explains that there has been inconsistent communication and cross-referencing between proceedings, resulting in unjustified exclusion of BTM DER. NFCRC believes that such an impactful decision requires a public record of decision, which is missing from the VDER docket and has not been decided if it is included or excluded in the CES proceeding. NFCRC states that because there is no detailed record of collaborative conferences and working groups, some of the outcomes were not included in the Staff Report. NFCRC also says that cross-referencing proceedings leads to unclear precedent.

NFCRC concludes that the content that remains to be developed on the valuation of DER far outweighs that which has been completed. NFCRC requests the Commission include specific Phase Two guidance in the Phase One Order.

NFG

NFG suggests that electric retail pricing must provide efficient value signals, as respects compensation earned by customers for the value that natural gas-fired DG, energy management, and other DER technologies provide. NFG advises that it is key that energy markets serving customers in western New York be structured to take advantage of the unprecedented and unique opportunity that NFG's close proximity to Marcellus

and Utica Shale production offers, perhaps exclusively to western New York. NFG urges the Commission to acknowledge the significant societal benefits of natural gas in New York, as a cleaner and more affordable fuel currently available to customers using propane, fuel oil, or diesel.

NFG points out that while the Staff Report cites technology neutrality, the recommended methodology is not technology neutral. NFG asserts that developing an exclusionary methodology that selects "winner" and "loser" DER technologies is not technology neutral, is inconsistent with the REV rate design principles in the Track 2 Order, and is inappropriate. NFG argues that Staff should have filed an extension request if additional time was necessary to complete a full analysis and put all DER technologies on a level playing field. NFG continues that the failure to install the capabilities of some DER types represents a lost opportunity, yet Staff has not contemplated or presented a compensation methodology to all New York ratepayers that may result from adopting Staff's incomplete compensation methodology.

NFG remains concerned about the recommended proposal to develop a Phase Two methodology in this proceeding. NFG claims that the current proposal would establish a two-year competitive advantage in the REV market, which would shut-out certain DER providers and market actors that can provide valuable benefits to the electric grid. NFG questions the value of perpetuating a two-year dialogue over content that has not been identified, across a timeline that does not exist. NFG urges the Commission to direct Staff to complete their analysis with input from the parties instead of adopting Staff's Phase Two proposal.

NFG notes that aside from limited eligible applications under PSL §§66-j and 66-l, natural gas is missing from Staff's list of technologies. NFG requests that the

Commission recognize natural gas a dispatchable DER technology that can provide valuable benefit to the electric grid, and allow natural gas DERs to receive the same compensation methodology as other dispatchable DER technologies identified by Staff. NFG claims that natural gas can backstop intermittent technologies, and the Commission should allow natural gas to backstop intermittent technologies in a non-discriminatory manner that is not different than energy storage.

NFG takes issue with Staff's assertion that applying the dispatchable compensation methodology to intermittent technologies that are not backstopped may present issues for project financing. NFG points out that Staff offers no analysis or support that a single DER compensation methodology would limit project financing, and states that project financing variability is actually because intermittent technologies are inferior resources compared to dispatchable technologies like natural gas. NFG advises that the Commission should reject the alternative compensation methodology for intermittent technologies that are not backstopped, and consider requiring natural gas or energy storage backstopping in order for intermittent technologies to receive compensation and ensure value is brought to the electric grid.

NFG claims Staff's Report does not include any outreach plans to make customers aware of their opportunities to opt-in to new compensation methodologies, and suggests that the Commission should require an outreach and education initiative for customers. NFG argues that Staff's recommendation to not pay credits to customers at any time will give customers a disincentive to generate more than their own usage, since they will never be able to be compensated. NFG proposes that customers be paid out credits in an administratively easy way such as annually, when they reach a certain dollar threshold, or upon customer request.

NFG asserts that the Commission should refrain from compensating the environmental benefits of renewable technologies because all DER technologies, including CHP generators using non-renewable fuels, should be treated equally. NFG goes on to point out that energy storage is not currently eligible for NEM, and is not eligible to produce credits in NYGATS. NFG also states that Staff's recommended plan is inconsistent with the benefits of natural gas stated by the Commission in a November 30, 2012, Order. Furthermore, NFG claims that the detrimental environmental impacts of manufacturing renewable technologies are undisclosed and not accounted for, and suggests DER technology manufacturers should be required to meet similar disclosure, disposal, and water treatment requirements that natural gas exploration companies must perform.

NFG suggests the Commission reject Staff's MTC proposal, until Staff's claims can be validated with numerical support and an appropriate compensation level can be calculated. NFG continues that rejecting the MTC will also eliminate the need for overly complicated tranches and the contentious and administratively burdensome issue of estimating the composition of community distributed generation projects.

NFG concludes by saying the Commission should reject the arbitrary cap on the developing REV market, which could be counterproductive to Commission policy objectives. Alternatively, NFG proposes to allow electric utilities to defer balances associated with compensation methodology revenue requirement impacts by either establishing a surcharge, or addressing deferred balances during rate proceedings.

Nucor

Nucor cautions that the cumulative weight of the REV suite of programs and mandates is particularly challenging in

economically strained Western and Central New York. Nucor asserts that as solar investments grow in size and significance, and DER scales increase, NEM produces an unacceptable cost shift of the utility's embedded revenue requirement to non-participating customers.

Nucor argues that the Phase One tariff proposal is not justified and would impose substantial additional costs and risks on New York consumers above what NEM now provides. Nucor points out two basic principles that are missing from the Staff Report: compensation should match DER performance; and, cost allocation and cost recovery should follow cost causation. Because NEM-based compensation is tied to bundled embedded cost-based rates, it does not in any way represent DER attributes and would only coincidentally approximate a DERs true value, Nucor claims.

Nucor criticizes the Staff Report muddling of considerations that produced several valuation method proposals that are thinly veiled compensation adders and unsupportable revenue stream guarantees. Nucor asserts this is apparent in the proposed generation capacity ICAP valuation method for intermittent resources, the Distribution Value element, and the proposed MTC for CDG installations. Furthermore, Nucor strongly maintains that estimating system or societal value of DERs is a distinct issue from the level of compensation and revenue guarantees that certain project developers need.

Regarding the Phase One MTC, Nucor opines that it largely negates efforts to develop a more precise value of DER since the compensation offered is simply a slight discount from NEM with the further complication of a long term fixed MTC. Nucor claims the Staff Report does not link CDG compensation to the value of DER, is not technology neutral, and favors CDG and solar PV development. Nucor argues that is imperative the Commission correct the imbalanced Staff Report that promotes CDG

above basic ratemaking and State policy considerations, and relies on key assumptions that lack basic factual support.

To better align the interim DER valuation and compensation in Phase One, Nucor proposes that the tariff not be technology specific by providing an alternative capacity payment to non-dispatchable intermittent resources, but assess value stack elements based on common criteria reflecting performance in providing system benefits consistent with NYISO requirements instead. In other words, Nucor proposes a technology forcing incentive for intermittent resources to pair with storage or otherwise improve their value as capacity resources. Nucor believes excluding DERs that may be more cost-effective or offer more reliable system benefits is a basic error. Additionally, Nucor asserts that neither value stack elements, nor the MTC should be fixed for long term periods. Nucor requests clarification regarding the specific cost allocation recommendations for reduced utility purchases of energy and capacity and environmental attributes. Furthermore, Nucor recommends a hard cap target of dollars or MWs applicable to all NEM and Phase One tariff projects.

Nucor characterizes an opt-in or other transition mechanism as a windfall to developers that unreasonably shifts normal developer business risk to captive ratepayers. Nucor argues it is premature to recommend all NEM and Phase One tariffs should be allowed a one-time opportunity to opt-in to a subsequent tariff, which should be addressed when subsequent DER tariffs are established. Regarding cost allocation, Nucor requests clarification that "the same customers" noted in the Staff Report recommendation to recover energy and capacity value compensation from the same customers that benefit from reduced utility purchases of energy and capacity refers to a utility's commodity sales customers. Nucor asserts that allocation of the cost of environmental values should remain with the customers

for whom a utility provides commodity service, not allocated to MHP or other delivery-only customers, if the Tier One REC acquisition runs with that bundled service.

Staff's proposal with respect to the net annual revenue impact limit raises multiple concerns for Nucor. Primarily, Nucor claims it will not halt excessive MTC-related cost shifts, and it does not limit mass market NEM-related cost shifts. Additionally, Nucor points out that pricing distortions caused by a fixed MTC could overwhelm the subsequent tranche discounts from the full NEM compensation if underlying energy prices increase as projected in the CES docket. Nucor recommends restructuring the proposed tranches, and suspending cost shifting elements of the proposed compensation method once the upper boundary of the Phase One tariff is met.

Regarding demand reduction value, Nucor argues it should only be offered to resources that provide a benefit sufficient for a utility to rely on when making system investment decisions, not simply a compensation adder that inflates the value stack.

NY-BEST

NY-BEST advocates that energy storage is a key enabling technology for the state to achieve REV, the State Energy Plan, and the CES goals. NY-BEST urges the Commission to adopt the Staff Report recommendation to allow storage paired with an eligible generating facility to participate in the Phase One program. NY-BEST also requests that the Commission work with the NYISO and distribution utilities to develop the most accurate market signals aligned with the peak cost hours in the tariff so that DERs have the information necessary to dispatch for maximum grid value.

NY-BEST encourages Staff and the Commission to work with NYSERDA to develop a solar plus storage intervention to

more fully capture the value provided by the combination solar and energy storage technologies. NY-BEST also supports the Staff Report recommendation that utilities should be required to develop unbundled tariffs that will increase granularity regarding the values and services, such as energy, capacity, ancillary services, and environmental impacts, currently embedded in average bundled rates.

NY-BEST requests the Commission consider amending the proposed Phase One tariff to include non-exporting, BTM storage immediately. NY-BEST claims that the system capacity value and local delivery value could be calculated and compensated with the Phase One tariff immediately, while the other values that storage can provide are further evaluated. NY-BEST advises that if the Commission does not change this in the Phase One tariff, then the Commission should address standalone storage as early as possible in 2017, and not wait to address this as part of the Phase Two tariff. NY-BEST states that in the absence of such action, private investment will continue to be held back from the state.

NY-BEST expresses concern with the Staff Report assumption that the retail rate is sufficient compensation for benefits related to energy and demand reductions BTM. NY-BEST explains that retail rates, whether volumetric or based on non-coincident peak demand, do not value reductions of energy consumption at system peak differently from reductions that take place when demand is low, despite the fact that reductions at peak can reduce costs. NY-BEST continues that clean generation that causes reductions in energy imports from the utility is of higher value than conventional generation that reduces imports from the utility in the same way. NY-BEST believes both of these concerns should be addressed as part of this proceeding.

NY-BEST concludes that their primary concern is that appropriate interim measures be put in place to ensure that New

York's grid is able to realize all of the benefits provided by storage.

NYC

NYC's comments offer several recommendations for improving the Phase One tariff as proposed in the Staff Report. First, NYC recommends that the proposed value stack be expanded to include additional value streams including avoided costs of local air pollution, land and water use impacts, and resiliency, and that locational adders should be adopted in Phase One to be applied to project compensation for projects serving customers in high-value public policy locations. NYC also advocates for increasing the value stack for high-value public policy locations, like NYC, where vulnerable customers (particularly low-income customers) have historically faced barriers to implementing renewable generation.

Next, NYC disagrees with the proposal to continue NEM for grandfathered on-site mass market projects while at the same time requiring CDG projects put into service after the issuance of the Phase One Order to receive compensation based on the Phase One tariff. NYC recommends treating load-modifying CDG projects equally to on-site mass-market projects and allow such projects to continue receiving NEM during Phase One.

NYC opposes the Staff Report's proposal to apply the MTC to 80% of generation from an eligible CDG project and believes that this 80% threshold will have a detrimental impact on CDG projects, particularly those comprised principally of residential and small commercial customers. Instead, NYC recommends that the MTC be applied based on a project's actual customer makeup, with the MTC applying to 100% of the generation allocated to residential and small commercial subscribers, and 50% of the generation allocated to large commercial and industrial subscribers.

With respect to RECs and other environmental attributes, NYC agrees with the proposal to allow customers compensated under the Phase One tariff to claim the attributes produced by NEM-eligible projects for the purpose of environmental and sustainability certifications. On the other hand, NYC opposes the restriction in the Staff Report that when a customer claims these attributes, the exported generation can be recognized as contributing to the state's overall CES goal but not the CES Tier One obligation, and NYC recommends that customer-retained attributes should be recognized as contributing to the CES Tier One obligation.

Next, NYC offers comments citing issues needing clarification with respect to cost recovery mechanisms in Phase One. NYC notes that the Staff Report appears to recommend that all Phase One costs should be recovered within utility service territories, but requests that the Commission confirm this point. NYC also requests clarification as to whether the Staff Report is referring to utility sales customers when it discusses recovering costs from the same customers that benefit from reduced utility purchases of energy and capacity and Tier One RECs. Additionally, NYC supports the proposal to determine the value of demand reduction and locational system relief by the portion of the value results from avoided lower voltage level costs and what portion results from avoided higher voltage level costs, but asks the Commission to clarify the threshold for lower and higher voltage. With respect to the Staff Report recommendation that MTC compensation be recovered from the service class of the project subscribers for CDG projects, NYC requests clarification as to whether it will be the utilities who track subscriber composition on a project by project basis.

With respect to the recommendation that projects entitled to continue receiving NEM have a one-time right to opt into the Phase One compensation, NYC requests clarification in

regard to whether the project will receive the compensation level available at either the time of opt-in, the project's in-service date, or some other date. Next, NYC opposes the proposed MW trigger that could result in mass-market projects transitioning to Phase One earlier than January 1, 2020 and recommends that the Commission reject this proposal. Finally, NYC that the Commission establish procedures to ensure the NYPA customers, like NYC, can participate in Phase One projects by the July 2017 implementation date, including addressing issues surrounding cost allocation.

NYLPI and NYC-EJA

NYLPI and NYC-EJA represent the REVitalize coalition, which includes PUSH Buffalo, UPROSE, and The Point. REVitalize submits their comments to highlight the concerns and interests of economically underserved and environmental justice (EJ) communities that may benefit from CDG. REVitalize cautions that the current VDER proposal will make CDG projects in LMI and EJ communities uneconomical to implement.

REVitalize advises that the VDER proposal should include additional value credits for social benefits, economic benefits, EJ siting, local workforce engagement, and use of local manufacturing base or materials. Additionally, REVitalize recommends an additional value credit if the project includes a community ownership component. REVitalize advises that the Social Cost of Carbon is not robust enough to capture additional benefits that should be valued. REVitalize suggests that the proposal primarily addresses the costs and benefits of distributed generation on how the grid functions, from the economic perspective of utility companies.

REVitalize claims that the current proposal discourages widespread renewable energy penetration by: establishing a Tranche system that caps the amount of energy

produced that can receive a higher valuation; and, by creating a VDER that is less than what a project would receive under the current net metering approach. REVitalize recommends revising or removing the Tranche system, and allowing LMI customers more time to pay interconnection costs than other projects.

REVitalize proposes allowing a project to choose the net metering value, or opt-in to the VDER scheme, depending on what is more economically beneficial for the project. REVitalize favors phasing in VDER over a period time when it is voluntary and financial returns may be measured. REVitalize concludes by suggesting that the value rate determined at the time of project development should be locked in for the entire life of the project.

NYPA

NYPA supports the recommendation that compensation to DER projects should come from the same group of customers who benefit from the utility savings. Flowing from that recommendation, NYPA comments that Con Edison distribution system customers should be allocated costs when they benefit from NYPA-customer DER located within the Con Edison service territory because all Con Edison delivery customers will benefit from distribution and locational system relief provided by those DER projects. NYPA believes that that the granular approach proposed will allow Con Edison tariffs to unbundle the components of the value stack to ensure that Con Edison ratepayers only compensate NYPA customer projects for the services that ratepayers benefit from. NYPA comments that to deny NYPA customers compensation for the delivery of benefits to the distribution system, while providing those benefits to other Con Edison delivery customers would result in rates that unduly discriminate against NYPA customers with DER.

NYPA also recommends that the Commission should 1) explicitly recognize that the energy exported from a qualified renewable DER facility creates Tier One RECs for CES compliance or other purposes; and 2) empower customers to choose whether to be compensated for the environmental value of such exported energy or retain the associated REC for disposition as the customer sees fit. To do otherwise, NYPA avows, may reduce the incentive for certain customers to invest in DER, which could lead to a chilling effect on the DER market.

Finally, NYPA supports the recommendation that renewable generation consumed on-site be tracked in NYGATS, in order to allow certificates to be retired for the purpose of environmental and sustainability certifications. NYPA asks the Commission to that renewable generation consumed on-site will be tracked in NYGATS in a manner that allows customers to comply with environmental and sustainability certifications including, but not limited to, the U.S. Green Building Council's Leadership in Energy & Environmental Design criteria, and New York State Executive Order 88.

NYSEIA

NYSEIA supports the Solar Parties' comments and emphasizes the importance of gradualism and stability as the state shifts away from NEM. NYSEIA recommends increasing the program size to 4% net utility revenue impact for DER deployment, because the 2% cap will trigger an arbitrary and abrupt deceleration in development in specific utility territories. NYSEIA emphasizes that this is especially true in the on-site mass market segment, which may breach the control mechanism in some territories within months after a Commission Order.

NYSEIA advises that the MTC should apply in full to 100% of CDG project output, with a more gradual 5% step down in

Tranches Two and Three. NYSEIA believes the proposed 10% decreases from retail rate net metering for the MTC by Tranche results in a steep decrease in value rather than a gradual shift away from NEM.

NYSEIA cautions that under the proposal, C&I and RNM customers will not receive full and fair compensation, but they should be compensated for all grid values. NYSEIA recommends a proxy Demand Reduction Value be assigned to C&I and RNM projects to approximate the delivery value not accounted for.

NYSEIA supports compensation based on the capacity portion of the utility supply charge, not the proposed peak hour options in the Staff Report. NYSEIA states that capacity compensation based on a set of peak hours would not capture the full value of distributed energy resources to the grid.

NYSEIA encourages Staff to lengthen the duration of the applicable compensation methodology to 25 years for all NEM eligible, in-service, and in-development projects. NYSEIA requests a consistent metric for locking in tranche reservations and an easily accessed and regularly updated web interface tracking progress with the tranches.

NYSEIA concludes by requesting gradual and transparent implementation. NYSEIA claims that to date, little information has been provided on how Phase One will be billed and tracked.

OGS

OGS argues that every kW and KWh of eligible generation should be valued and compensated equally based on the locational and temporal value of the project to the grid, and without regard to how the project is interconnected or how the output is consumed. OGS claims that all DERs should be compensated equally and fully based only on that DERs value to the grid. OGS claims that under the proposal in the Staff Report, resources defined as belonging to the on-site large

projects and customers will be significantly undervalued and undercompensated, especially compared to CDG projects. OGS suggests that a BTM MHP project is used to offset existing load, and is essentially guaranteed to provide system relief.

OGS believes the LBMP for energy compensation correctly recognizes the value of exported energy. OGS takes issue with the fact that the value stack applies only to net exports from a DER hosts account on an hourly basis, so a large BTM MHP project is unlikely to see the same recognition of its ICAP value as a CDG project. Similarly, OGS points out that a CDG project and a BTM MHP project would have equal demand reduction value and locational system relief. However, OGS states that because the BTM MHP project would not export any generation, it would receive no compensation for its contribution. OGS suggests that the MTC is inappropriate because a large BTM MHP project provides as much value as, if not more than, an equivalent CDG project and they should be compensated equally.

Pace

In its comments, Pace offers general support for the proposal to create limited value stack, coupled with a Market Transition Credit elastically linked to the retail rate, which is offered through a series of tranches that limit the sum of all non-value compensation to a 2% bill impact. Further, Pace supports the recommended structure for tranches 0 and One. Next, Pace supports the proposed intention to unbundle the values and services currently embedded in average bundled rates, and believes this will be a valuable exercise that will complement the efforts undertaken in the VDER proceeding.

Pace criticizes the Staff Report in that in assessing the five distinct areas of DER value, the Staff Report borrows existing market values, or leaves the value undefined for future

development. While this may be appropriate in some cases, Pace comments that this does not represent a methodologically sound approach, particularly for environmental and locational value. Pace opposes several aspects of the proposed MTC tranche structure and does not believe a basis has been established for claiming ratepayer impact, and thus does not support the 2% cap on bill impacts proposed in the Staff Report.

Next, Pace comments that RECs attributable to DER should not be counted towards either Tier One of the CES or the state's overall baseline unless the producer of the REC affirmatively makes a sale into compliance markets. Pace further disagrees with the proposal to allow RECs attributable to power produced and consumed on-site and RECs related to net exported power to be recognized as contributing to the state's overall CES goal. Pace also opposes the restriction on receiving environmental value only for net monthly exports and believes that such a restriction will serve as a significant disincentive to customers installing storage.

Pace is also unsupportive of the proposal that capacity payments for dispatchable resources be linked to ex-post measured performance during their utility's highest demand hour of the previous year. Pace also disagrees with the recommendation that excess credits be carried over each billing cycle and not paid out at any time because doing so may create an incentive against larger DER systems that cannot net their total generation against the customer bill.

With respect to the proposal to apply the MTC to only 80% of the generation of eligible CDG projects, Pace recommends that those project be eligible to receive the DRV for the remaining 20%. Pace supports the structure by which mass market systems will receive NEM moving forward, as well as the notice requirements for utilities to alert market participants of their proximity of the cap, but encourages the Commission to provide

more guidance on the process by which mass market compensation will be determined after the caps have been reached.

Next Pace recommends that a process involving public participation be utilized to establish LSRV and urges the Commission to be specific in establishing a process by which utilities will identify LSRV. Pace also recommends measuring and accounting for wholesale price suppression in Phase Two. Finally, Pace offers that non-energy benefits identified in the Staff Report should be accounted for in the DER valuation methodology.

PULP

PULP offers comments opposing the proposal to continue NEM for projects until 2020 because NEM have been acknowledged to be imprecise and the Staff Report offers little justification for grandfathering projects in such a manor. Additionally, PULP comments that the Commission should not adopt delivery service rates that are imbued with pricing values that are primarily designed to support an unregulated and profit-making business model based on values that have neither been definitively demonstrated in the marketplace, nor have been placed in this record and supported by objective facts. Additionally, PULP asserts that there is a lack of evidence that the assumptions about any of the wholesale market and distribution or delivery related benefits cited in the Staff Report which would justify the subsidy provided. Further, PULP challenges the assertions that rooftop and community solar programs provide benefits to the distribution system associated with line losses and avoiding future distribution service investments, and states that such benefits rely on hypothetical avoided distribution service costs and have not been shown to actually avoid the essential services included in delivery rates.

PULP also comments that it is inappropriate to compare the approach to arriving at the NEM value stack to how efficiency programs are approved for cost recovery from ratepayers because the latter function is delivered by regulated entities or subject to the oversight of regulated entities and the former is performed by unregulated entities. PULP comments that the Staff Report does not include any information on the costs and bill impacts associated with the current net metering policy and further that, by nature, NEM shifts costs unpaid and unavoided essential distribution services from solar customers to non-participants, who are often lower-income customers.

Next PULP comments that the subsidies provided to DER programs by all ratepayers should not be based on a predetermined and hypothetical set of values assigned to DER, but instead, rates should reflect prudent costs incurred by utilities and rates for market based products and services like DER should be based on market-based pricing principles. Further, PULP rebuke's the Staff Report for failure to consider the least cost benefits of solar generation in its pricing methodology.

Finally, PULP comments that the Phase One Value Stack repeats the defects of the existing NEM policy in that it requires customers to pay unregulated entities for a hypothetical value subsidy in distribution rates. PULP states that the Staff Report does not identify this bill impact in terms of overall costs that might be imposed on residential ratepayers under either the current net metering policy or its proposed Phase One compensation methodology. PULP recommends that the Commission require utilities to undertake a fact-based analysis of the actual benefits any DER project might deliver to regulated ratepayers prior to justifying payments to such providers, and that such payments should be based on actual performance in achieving those benefits.

SolarCity

SolarCity generally supports the proposals set forth in the Staff Report, but cautions that market growth forecasts and total market size allocated to the on-site mass market segment may result in triggering the market control mechanism well in advance of the Jan. 1, 2020, date. SolarCity suggests Staff examine reforms that are needed within existing policies and programs, such as available time-of-use rates and demand response, which would remove barriers to energy storage adoption and unlock the value of storage to the grid and to customers.

SolarCity proposes that Staff outline an initial set of services and impose a July 1 deadline for utilities to develop proposals for virtual generation resource and fee-based portfolio. SolarCity continues that successful implementation of a smart energy home rate is crucial to develop a Phase II tariff.

SolarCity signals that the proposal to continue NEM treatment for existing projects for 20 years would give customers and investors confidence that their financial decisions based on existing policies may not be abruptly betrayed in the future.

SolarCity advises that stakeholders should have visibility into the utility methodology of what portion of the reduction of demand and locational relief value benefits are allocated to lower and higher voltage customers. SolarCity suggests the Commission give an opportunity to comment on these allocations of costs and benefits across service classes.

SolarCity generally supports a 2% cap on revenue avoided by participating customers, but proposes Staff and utilities develop utility-specific caps and revenue impact mitigation measures in individual utility rate cases.

SolarCity favors volumetric crediting of CDG customers as a simpler tool than monetary crediting. SolarCity expresses

concern in the utilities' ability to manage the bill complexity of Staff's proposal. SolarCity stresses the Commission and Staff should closely observe customer credits to verify correct calculations and allow for a streamlined customer complaint resource.

SolarCity submits that customers should be compensated for carried-over credits, and advises that the year-end compensation should be modeled on the NEM statute.

SolarCity agrees with Staff's proposal to not modify rebates or incentives within this proposal, but points out several designs within the NY-Sun Commercial MW Block Program that may be incompatible with Staff's Phase One tariff proposal. SolarCity advises resolution of this and other discrepancies.

SolarCity believes a limited continuation of the existing CDG policy in Tranche Zero is appropriate due to the extremity of the interconnection queue, but otherwise disagrees with retroactive policy making. SolarCity comments that the Commission should note the extremity of the situation and commit to limit any other retroactive policy changes.

Generally, SolarCity supports the value stack approach. SolarCity notes that mandatory hourly pricing (MHP) values as a proxy for energy value generated by a project is appropriate, and proposes that large onsite projects with storage be able to charge on MHP even if the customer is not on this pricing scheme. SolarCity cautions that the current proposal to credit customers for wholesale capacity and capture ICAP value offers aggregators and customers no visibility into when to operate to be in line with system peak. SolarCity advises requiring day ahead notification to customers and aggregators to maximize system value. SolarCity believes that more work is needed to quantify and value omitted externalities in the renewable energy attribute auction price. SolarCity disagrees with Staff's assertion that attributes generated by

energy used on-site must be retired, thus ineligible for compensation. SolarCity limits support for using a proxy value for demand reduction and locational system relief based on the Commercial System Relief Program only as an interim. SolarCity believes this method is not adequate to represent locational value, should consider 20 years instead of 10, and that there should be stakeholder input on utility-developed locational relief values.

SolarCity believes the Commission should allocate additional capacity to the residential segment and increase the 2% revenue requirement shift to give the industry a more gradual transition. SolarCity argues that PV projects with storage should be able to provide either on-site demand and load reduction or export for the VDER tariff, not be limited to one function. SolarCity labels Staff's proposal to provide MTC to 80% of export as inadequate, and suggests MTC should be allocated to 100% of export. SolarCity fully embraces developing virtual generation resource and fee-based portfolios in every IOU territory, and says they should model the existing Con Edison demonstration project.

SolarCity concludes by requesting the Commission its Petition filed October 21, 2016, at the same time as the order resulting from the Staff Report.

Solar Parties

Solar Parties support the recommendation to continue NEM for projects in service at the time of the Phase One Order. Solar Parties also agree with the proposal to allow NEM customers to opt in to the Phase one tariff, but further recommend that customers also have to opportunity to opt out in order to encourage customers to experiment with the new tariff.

Solar Parties do not support to proposed 2% cap on net annual revenue impacts and instead recommend a 4% cap. Solar

Parties aver that a 4% limit is more reasonable when proper cost allocation and recognition of the benefits delivered by solar systems is considered. Additionally, Solar Parties believe that 4% upper bound will allow the market to scale at an early stage in development, will ensure that residential customers who cannot participate in the onsite mass market have an opportunity to participate in the CDG market, and will better facilitate achieving the Governor's solar objectives and the state's clean energy goals.

With respect to the 20 year term for the Phase One tariff, Solar Parties disagree with placing a limit such as 20 years and instead recommend allowing projects to maintain net metering, or the subsequent VDER tariff as applicable, for the life of the project. Alternatively, Solar Parties recommend adopting, at the minimum, a 25 year term.

Solar Parties support the following recommendations in the Staff Report: 1) utilization of monetary crediting; 2) the hourly metering requirement; 3) carrying over credits on a monthly basis; 4) keeping projects on their current rate in the case of project transfer or subscriber turnover; 5) projects on NEM or the Phase One tariff remain eligible for NYSERDA incentives; 6) changes in underlying rates for DER customers; 7) treating behind the meter generation as load reduction, and to apply the Phase One Tariff to net injections only; 8) fixed locational value based on the MCOS and values put forward by the utilities; 9) maintaining NEM for projects in service until 2020; 10) launching an initiative reviewing smart inverter requirements; 11) considering time of use rates in Phase Two; 12) application of Phase One tariff to new CDG projects;

Solar Parties also support the recommendation regarding grandfathering, but note that this type of capacity-limited grandfathering is not an appropriate precedent for future policy transitions. Further, Solar Parties recommend

establishing increased transparency regarding project eligibility.

Solar Parties accept the recommended approach to use the actual day-ahead NYISO hourly LBMP energy price for the energy value, but believe that this should include all of the components of zonal LBMP, including energy, congestion, and losses. Solar Parties caution however that this approach also creates more uncertainty and complexity for developers, which ultimately makes financing more difficult and erodes the value proposition for customers.

With respect to the value of installed capacity, Solar Parties support the recommended approach to valuing capacity, and further request that Staff identify a rate class to be used as soon as possible, stating that SC1 should be used. Solar Parties also support the use the higher of the REC value based on the NYSERDA published price and fixed for a term consistent with grandfathering and tariff term length, or the social cost of carbon when determining the economic value.

Turning to the proposed DRV, Solar Parties oppose the recommendation as structurally flawed and based on incomplete information. Solar Parties comment that it would be very difficult to finance around the DRV, resulting in lost value from the overall stack, and that it is critical that a strong foundation be set for each component in the value stack, as the foundation established in Phase One will inform the later phases. Solar Parties propose adopting a proxy DRV based on the full territory-wide MCOS value, a greater number of hours, and a multiyear average for the interim tariff, and recommend leaving further development of the DRV to Phase Two.

Solar Parties support the recommendation concerning the MTC, but have concerns with respect to the proposals for its application. Solar Parties oppose the proposed step downs between tranches and recommend a 5% step down instead.

Additionally, Solar Parties recommend that CDG generation be paid 100% of the residential MTC for each tranche, rather than 80% proposed in the Staff Report. Solar Parties also propose that tranche sizes should be derived assuming that MTC compensation will be recovered from the residential class commensurate with the assumed residential subscription rate, as well as a number of adjustments for calculating the MTC. Next, Solar Parties comment that while the Staff Report proposes the MTC as a placeholder value, it does not recommend a similar placeholder for C&I/RNM projects. The Solar Parties urge the Commission to adopt a proxy DRV and LSRV values to account for the delivery value of DERs that has yet to be established through a more granular approach.

Solar Parties support the recommended approach to the MW trigger, but are concerned that it is based on an overly conservative projection of market growth. Finally, with respect to the net revenue impact estimated in the Staff Report, Solar Parties comments that the Staff Report's analysis does not represent revenue losses to the utility, because any difference between revenues and costs would be recovered through either a decoupling rider or an increase in base rates. Additionally, Solar Parties continues, the net revenue impact does not represent the shift in revenue recovery from CDG participants to non-participants, since it would be recovered from all ratepayers in proportion to each ratepayer's energy usage.

TASC

TASC supports the recommendation that all projects in service as of the date of the Phase One Order will continue to be compensated based on the applicable Net Energy Metering methodology. TASC also supports the recommendation to continue NEM for mass market customers. TASC supports the recommendation to continue mass market growth during Phase One, and proposes

that a MW trigger for Commission review of mass market activity be adopted, and that any trigger provide continuity with Commission timelines regarding the development of Phase Two.

With respect to time of use rates, TASC supports the recommendation to consider time of use rates under Phase Two, and welcomes Staff's recommendation regarding a review of smart inverter requirements. TASC supports the recommendations regarding storage in section 2.2 of the Report, but notes that the economics of storage are still challenging in many applications and thus supports the proposed "solar plus storage" incentive program to be developed by NYSERDA in 2016.

Finally, TASC supports the recommendation to treat instantaneous on-site consumption as load reduction. TASC comments that treating instantaneous on-site consumption of generation as load modification similar to energy efficiency, or other methods of instantaneous load reduction is the defining feature of the net metering construct and is key to customer adoption. Similarly, TASC supports the application of the Phase One Tariff to net injections only.

UIU

UIU proposes that it is equally important to formally recognize parallel proceedings regarding consumer protections that will affect DER providers as it is to move towards a more accurate DER valuation. UIU requests that the Commission formally acknowledge the ongoing proceeding to establish a set of UBP regulations for DER providers. UIU cautions that insufficient customer protections may enable inexperienced developers to inadvertently harm customers or attract bad actors, and advises that DER contracts extending for twenty years or more may compound the resulting customer harms.

As UIU proposed for ESCOs, UIU suggests the Commission establish a DER performance bond process to insure ratepayers'

investment in the DER market. UIU acknowledges that a performance bond may make it more difficult for some DERs to enter and remain in the market, but believes this consumer protection is prudent.

REPLY COMMENTS

Acadia and NRDC

Acadia and NRDC filed joint reply comments, whereby they oppose the comments of the JU as those comments offer several radical changes to Staff's proposal never before discussed in the collaborative. Acadia and NRDC comment that the JU analysis that is difficult to follow and impossible for other parties to comprehensively evaluate at this stage of the proceeding and that the JU projections appear on their face illogical. Acadia and NRDC urge the Commission not to rely on supplied by the JU, but instead to rely on the methodology in the Staff Report, which was shared in detail with the various collaborative participants and developed throughout the collaborative process.

AEEI

In response to the comments of the JU, the AEEI offers that the results of the JU calculations diverge significantly from those contained in the Staff Report. The AEEI cites three problems with the JU suggestion to base DER compensation on modeled output of solar during the last five years. First, solar production profiles do not represent other eligible DER technologies. Second, this method would hinge upon modeled output for a single sample year, as opposed to the more accurate Staff proposal which is based on actual, metered data during the prior year's peak. Third, the JU's proposed modeling suffers from an analytical problem because it relies on solar irradiance data collected from the wrong days. Thus, the AEEI supports the

Staff proposal to use technology-agnostic metered data rather than solar-only modeling results.

The AEEI also comments that the JU made an error in calculating the customer bill impacts; the JU did not properly interpret the results of their analysis and thus reached two conflicting conclusions. The AEEI also notes that both the Staff Report and the JU analysis calculated the revenue impacts assuming that all

DERs would be solar, producing output for this technology only, and that other technologies may have significantly better capacity factors in the top 10 load hours.

Next, the AEEI propose that utilities should increase the granularity of the MCOS studies to more accurately reflect distribution value, and that incremental LSRV may reflect either an increase or decrease in value. The MCOS studies, the AEEI continues, are critical to the quantification of distribution value and should be open to public review of data and methods.

The AEEI strongly disagrees with the JU calculation that shows community solar projects achieving an 80% profit margin and the implication that the Staff proposal would result in a windfall for developers. The AEEI cites two major flaws with the JU calculation; 1) they assumed a discount rate of only 2%, which is unrealistic and lower than the cost at which the U.S. Government can currently borrow; and 2) the analysis ignored many of the expenses that the CDG would incur, including customer acquisition costs and ongoing administrative costs.

The AEEI shares the concerns of other commenters that the Phase One Tariff will leave two critical values, capacity and environmental benefits, without compensation for energy that is produced and consumed behind the meter. With respect to achieving a more accurate compensation mechanism for storage, the AEEI supports the proposal by SolarCity to storage be allowed to charge using the Mandatory Hourly Pricing tariff,

providing a way for storage to participate in economically beneficial arbitrage.

With respect to the proposed treatment of environmental attributes, the AEEI shares the concerns expressed by other parties with the method proposed in the Staff report. The AEEI supports the proposed solution by Pace for clarifying the ownership of RECs, protecting against double counting, formulating reasonable and meaningful baselines, and ensuring that the critical concept of regulatory surplus is protected. The AEEI recommends that all generation from an eligible generator, regardless of whether it is consumed onsite or exported, should generate RECs if the customer forgoes environmental compensation.

With respect to distribution capacity, the AEEI opposes MI's suggestion that the Locational System Relief Value should vary annually like the Demand Reduction Value, instead of fixing the value over a 10-year period as failing to recognize a key distinction between these two distribution system values. AEEI instead supports the Staff proposal.

Next, the AEEI agrees with Pace that for any project that receives the MTC for any portion of its generation, the DRV should apply to the portion of the generation that does not receive the MTC. Additionally the AEEI supports the proposal that the calculations for translating the acceptable cost increases to customers into tranche sizes should be carried out by Staff and be open for public review and comment.

The AEEI recognizes the possible market distortions and unintended consequences within the Staff Report presented by CORE, including increasing the prevalence of CDG projects and leaving otherwise viable on-site DER opportunities undeveloped. Additionally the AEEI challenges MI's concern with allowing NEM customer the option to opt-in to the Phase One tariff and notes that a project is only likely to switch from NEM to the Phase

One tariff if there is a high LSRV available, meaning that the project would be fulfilling a specific grid need. Finally, the AEEI supports AEMA's recommendation that payments for dynamic load management programs should reflect the environmental benefits that demand response provides.

AEMA

In its reply comments, AEMA reiterates the list of issues that were deferred during Phase One discussions, but that it believes should be addressed immediately during the first quarter of 2017 in order to level the playing field as much as possible between technologies that were considered in Phase One and those that were not, resolving differences in compensation between technologies that provide similar grid services. With respect to Phase Two, AEMA urges to the Commission to avoid delay in deciding Phase Two issues and recommends that the Commission: 1) design tariffs that are standardized across technologies, applications, and services to provide the same compensation for similar services, no matter the method of delivery; 2) Allow for consumers to access multiple benefits streams of DER technologies, applications, and services; and, 3) Develop consistent and transparent planning and procurement processes so that all DER can participate competitively and on an equal playing field. Finally, with respect to the format of subsequent phases, AEMA recommends that the Commission: 1) encourage rich engagement with stakeholders during subsequent phases and build a foundation of credible analysis to model innovative solutions; and, 2) coordinate with the NYISO as it works through integration of DER into the wholesale market, to ensure that both entities are inclusive and consistent.

Bloom Energy

Bloom Energy supports the comments of other parties who propose to include energy consumed behind the meter in the Phase One value stack. Bloom Energy comments that excluding behind the meter projects is adverse to the foundational principles of REV and would have a serious chilling effect on the development of customer sited distributed generation.

Next Bloom Energy recommends including the values associated with criteria pollutant reductions like SO₂, and NO_x in the Phase One values stack instead of waiting until Phase two. Finally, Bloom Energy supports the comment of parties who recommend maintaining the eligibility of traditional incentive programs, like CES, for behind the meter resources.

CCR

In its reply comments, opposes the assertions made in other party comments with respect to the scale and cost of solar in New York, the Value of DER being less than retail rate, and the regressive nature of NEM. CCR challenges the JU's revenue impact analysis and the conclusion that customer impacts as high as 25% will result. CCR also challenges the assertions that solar developers are making excessive profits in an overly incentivized market, and that the assertion of 90% gross profit margins should be disregarded in its entirety. CCR also oppose the recommendations to shorten the grandfathering term for mass market NEM customers. CCR recommends retaining the proposal in the Staff Report and that the grandfathering term be no less than 20 years.

CCR further disagrees with the recommendation of MI to reduce the compensation period under the Phase One methodology, and instead supports the comments of several solar parties that the compensation period should be extended to 25 years. CCR also opposes the recommendation by MI to eliminate the option

for DER projects to opt-in to the new valuation methodologies both for projects eligible for NEM and those under the Phase One tariff.

With respect to the changes proposed by other parties to the components of the value stack, CCR comments that many are either inadequately supported or more appropriate to consider in the development of the Phase Two methodology. Specifically CCR recommends that; 1) losses should be included in the valuation of energy; 2) the capacity value should be derived from the SC1 supply rate for the Phase One tariff and then worked on gradually to more accurately reflect the contribution of solar; 3) there should be no assumption about the impact of DER on ancillary services at this time; 4) the calculation of the DRV should be modified to improve its accuracy and limit its volatility; and, 5) that the solar generation profiles should be standardized on a realistic set of real-world conditions for each service territory including the impact of near-field shading and snow.

Additionally, CCR urges the Commission to reject the recommendations for the elimination of a value stack credit for the environmental benefits of solar or the use only of the Social Cost of Carbon. CCR supports the Staff Report's proposal to use the higher of the REC value based on the NYSEERDA annual published price for compliance or the social cost of carbon from the BCA Framework Order.

With respect to the comments concerning the MTC, CCR opposes, as inconsistent with the intent of current transition, the proposals to: 1) eliminate the MTC; 2) shorten the timeframe for the MTC; 3) increase the number of MTC tranches and/or create steeper step-downs from NEM between tranches; and, 4) allocate the MTC to only 60% of generation from CDG Facilities.

Finally, CCR supports the Staff Report's proposal that RECs for NEM and Phase One Tariff projects be retained and

automatically retired by the customer. CCR offers that these RECs should not count toward the Tier One obligations of the LSEs, but can still being tracked and recognized as contributing to the overall State CES goals.

CCSA

CCSA offers reply comments to those filed by the JU and UIU. First, CCSA asserts that the profit margins for CDG presented by the JU are based on a faulty and incomplete model that bears no relation to the reality of solar project development in New York. Along those lines, CCSA notes that the JU model; 1) improperly utilizes a 2% discount rate when calculating a CDG project's profit margin; 2) fails to accurately represent project costs; 3) does not reflect the reality that CDG project developers must provide a discount to customers from the value of the VDER credit; 4) does not account for the federal investment tax credit; 5) includes several errors in inputs, including double-counting the value of the NY-Sun incentive and using historical rather than current values for LBMP and ICAP in the value stack; and 6) omits entire categories of costs beyond financing.

Next, CCSA challenges the JU's use of raw total of interconnection applications in the queue, stating that it is not reflective of actual anticipated development. Additionally, CCSA comments that the JU analysis of the bill impacts of other policies adopted thus far is one-side in that it does not reflect any benefits of those policies. CCSA supports the comments by the Solar Parties with regards to the utilities' rate impact analyses. With respect to the comments filed by UIU, CCSA shares UIU's concerns with consumer protections and comments on the multiple industry initiatives that demonstrate those shared goals.

CORE

In its reply comments, CORE requests that the Commission ensure: 1) that the on-site renewable energy generators own the environmental attributes associated with their projects; and, 2) on-site and remote net metered renewable energy projects are compensated for the value of their generation on a nondiscriminatory basis with CDG and irrespective of whether the generation is consumed on site or exported to the grid. CORE echoes the concerns of other parties that Staff's proposal may unduly tilt the field in favor of CDG to the economic and competitive disadvantage of other DER. CORE urges the Commission to expressly affirm that on-site generators/customers have the right to register their renewable projects in NYGATS and own, retain, and trade the RECs associated with their projects' output.

DSUN

In its reply comments, DSUN challenges the JU's calculations which suggested that developers would be overcompensated, resulting in gross profit margins of 80%. DSUN instead calculates developer gross profit margins to be -14%. DSUN cite several flaws with the JU calculations, including: 1) erroneous sampling; 2) underestimating interconnection costs; 3) incorrect discount values for NPV calculations; 4) miscalculation of the value of incentives available under the NYSERDA MW Block program; 5) utilization of a calculation of gross profit margin inconsistent with industry norms; and, 6) the use Tranche One values to represent the revenue streams for investors while at the same time calling for a reduction in Tranche One sizing.

In order to address the challenges faced by developers by the proposed VDER compensation rates, DSUN recommends that the utilities be directed to help developers reduce costs by

ensuring interconnection fees for CDG projects average \$0.03/W_{DC}, as indicated by their own model of developer costs, and by providing transparency in cost estimates, open cost book, a commitment to variability of no more than 10%, and post-COD comparison of actuals to estimated costing.

DSUN supports the comments of SEIA and Vote Solar, CCSA, Cypress Creek, and Pace suggesting a longer term for the Phase One Compensation stack. DSUN supports extending the Phase One Compensation stack to 25 years, with 25-year fixed terms for the MTC and the Value of "E". DSUN also recommends that the Commission clarify that volumetric NEM will not be limited to any specific term. DSUN also supports increasing the term for the compensation for projects grandfathered into NEM to 25 years.

DSUN supports applying 100% MTC credit to projects declared as 100% residential as a way to relieve the burden on residential imposed by projects with a low residential to commercial mix that receive an inordinately high level of MTC, and provide the foundation for inclusion of more low-to-moderate-income subscribers.

DSUN also supports the comments from SEIA, NYSEIA, CCSA, and Cypress Creek calling for a 5% step down in compensation between tranches rather than the 10% recommended in the Staff Report. Additionally, DSUN supports the comments from Borrego Solar on real-time updates to the tranche statuses.

JU

It its replies, the JU reiterates several of its initial comments, including the suggestion to replacing the 2% bill impact cap with an alternative approach that would consider limiting incremental CDG growth to a number of MWs corresponding to five percent of each utility's forecasted, weather-normalized 2015 peak load at the time of the NYISO peak. The JU oppose the

proposal in several comments to develop utility caps and cost recovery mechanisms in individual utility rate cases as such an approach could have the unintended effect of adding to market uncertainty and delaying the transition to a more value-based compensation mechanism for several years, as utilities may not have imminent rate case filings.

The JU agree with parties who support the Staff Report's inclusion of a wholesale energy and capacity values in the compensation structure. Additionally, the JU support comments favoring a performance-based capacity payment, and disagree with parties who advocate for a fixed capacity payment based on the SC1 residential capacity charge for CDG projects.

As stated in its initial comments, the JU supports modifying the methodology to compensate for distribution value by applying the Staff Report's DRV methodology CDG projects receiving the MTC, and having a portion of the MTC be valued with the DRV 10 peak-hour mechanism as a proxy for system-wide distribution benefits. The JU opposes other parties' suggested changes to the Staff Report's DRV proposal. The JU reiterates its support for the Staff Report's recommendation to use future marginal cost studies to determine locational performance based CDG credits and again offers proposes to shorten the compensation period to five years.

Next, the JU oppose parties who comment that argue that using RECs as the mechanism for valuing the environmental attributes of clean DER does not aligns with past Commission policy. Further, the JU agree with party recommendations that the creation of RECs should not be limited to exported generation. The JU shares other parties concerns with the potential double counting of RECs and propose that customers should be able to choose whether they will retain their RECs without compensation, or sell them and receive payment for them from the utility.

The JU oppose party suggestions to modify the approach to gradually transition to more value-based compensation by using the MTC based on concerns regarding unintentionally harming projects that would exclusively target residential and small commercial customers. It believes this concern could be resolved through the JU's recommendation to provide the MTC for 100% of projects that certify and maintain 100% residential and small commercial subscribers, while all other projects would receive the MTC for 60 percent of output. The JU generally support the approach to use five-year average LBMP data to establish the expected average energy rate that a solar installation would earn and disagree with parties who argue that this differential should be calculated using 2016 numbers only. Additionally, the JU argue that this approach could be improved by simply ignoring this differential for the purposes of calculating the MTC.

The JU clarify its initial comments with respect to the potential that Tranches Zero and One may lead to higher than necessary levels of compensation for CDG projects. The JU note that they do not know the net profit margin or net income for these projects, or for the companies and individuals who develop them and that the JU analysis does not account for all costs, including financing costs. The JU comment that the purpose of offering such an analysis is to highlight the need to consider that costs of CDG are lower than the costs of mass-market rooftop installations, and are declining.

With respect to grandfathering, the JU support parties who favor establishing a fixed grandfathering period and MTC payment period and oppose comments suggesting that grandfathering and MTC payments should continue for the life of the project. The JU again recommend that the grandfathering period should be limited to 15 years, and the MTC payment period

limited to 10 years, with the distribution component guaranteed for only five years.

The JU also support comments advocating for including low- and moderate-income customers within the development of the Phase One tariff. To achieve this goal, the JU proposes that either: 1) CDG projects could be required to reserve a small portion of its output for low- and moderate-income customers; 2) CDG projects could be allowed access to Maintenance Tier funding under the CES, which could be expanded to provide additional assistance to low- and moderate-income CDG projects demonstrating a financial need; or, 3) tranche allocations could be prioritized to accommodate projects serving low-income customers.

NFCRC

NFCRC supports the comments of other parties stating that the numerous attributes of power generated and used onsite should be appropriately valued, consistent with REV principles. On the other hand, NFCRC disagrees with the SEIA assertion that behind-the-meter generation should be treated only as load reduction, and that the Phase One Tariff should apply to net injections only. With respect to the economic and environmental value created by onsite generation, TASC supports the comments by other parties that the lack of price signals for self-consumed generation that avoids emissions or that provides capacity relief will negatively impact New York's ability to achieve its system efficiency and carbon reduction goals.

NFG

In its reply comments, NFG states that, although the Staff Report claims to be technology neutral, it has the outcome of manipulating the REV market by creating barriers of entry, dictating which market actors can viably participate. Instead

of adopting the Staff Report, NFG recommends establishing broad policy applicable to all technologies, especially natural gas, which would allow market actors to develop innovative ideas, strategies, techniques and products to fulfill those objectives.

Next, NFG comments that there is no merit to the claims that price volatility exists in the natural gas markets. NFG explains that the volatility experienced in the winter of 2013 to 2014 was the result of a shortage in pipeline capacity, not a shortage of natural gas supplies. NFG asks the Commission to reaffirm its commitment to support the expansion of natural gas pipeline infrastructure.

Next, NFG opposes the recommendation by the JU to establish an upper limit on the amount of CDG that can be installed under Phase One. NFG comments that an arbitrary cap on CDG development does not allow room for industry development, and does not send signals that significant development opportunities exist. Additionally, with respect to the JU's concern with intermittent renewable technologies, NFG notes that CDG does not need to be fueled solely by renewables and that CDG projects could be fueled entirely by natural gas, which is dispatchable, and available on demand immediately.

NFG also opposes the recommendation that the Commission should give Staff clear authority to make an independent evaluation of the social cost of carbon, given the uncertain future of the federal process. NFG notes that there is significant disagreement amongst parties in this proceeding and that the Commission should not delegate its decision making authority to Staff. Finally, NFG reiterates its suggestion that the Commission refrain from adopting compensation for environmental benefits at this time for several reasons, including the fact that the Staff Report proposal fails to account for detrimental environmental impacts that can be caused

by the manufacture of renewable technologies such as solar panels.

NYC

In its reply comments, NYC oppose the recommendation by the JU to adjust the Phase One tranche sizes. NYC comments that the JU proposal is a significant departure from the Staff Report and urges the Commission not to utilize the JU calculations. Additionally, NYC recommends that the Commission reject the JU proposal to reduce the MTC payment period to 10 years, and continues to support the proposed 20 year period as it will provide certainty to developers and customers transferring to the new Phase One compensation methodology. With respect to the JU's recommendation to require quarterly filings by the utilities reporting on bill impacts resulting from the Phase One tariff, NYC supports such transparency, but opposes taking short-term actions based on such quarterly reports, and instead, recommends that the Commission only act upon the utility bill impact reports once a full year's worth of data has been reported. Finally, with respect to Phase Two, NYC recommends that Phase Two commence with a Staff Straw Proposal and that working groups which focus on discrete topic areas should be established.

NYSULC and Local 10

NYSULC and Local 10 offer reply comments in support of those filed by the JU. NYSULC and Local 10 agree that NEM fails to accurately compensate DER compared to the value provided to electric grid stakeholders, and believes that if proper tariffs are not applied to DER, it will place an unfair, higher rate burden on all electric consumers. NYSULC and Local 10 share the JU's concern that the Staff Report: 1) is based on inexact data and assumptions that result in levels of DER growth that cannot

be sustained within a 2% customer bill impact; and, 2) appears to provide compensation to all DER projects irrespective of whether the project attributes are valuable to deferring generation or distribution system investments. NYSULC and Local 10 cite a number of issues in the Staff Report that still need to be fully explored in order to develop policy and standards that will guide the development of future economically-efficient resources through the placement of a value on each of the differing DER characteristics including time-based, locational and operational values.

OGS

OGS offers reply comments in response to the comments submitted by the JU. OGS concurs with the conclusion drawn in the JU comments that the methodology proposed in the Staff Report will result in disparate compensation for different resources, despite those resources supplying identical, and occasionally superior, benefits to the grid. Further, OGS agrees with the JU assertions that the proposed Phase One methodology will result in excessive compensation levels that are unnecessary to meet the stated policy objectives, and would instead result in excessive profit margins for CDG developers. OGS comments that behind-the-meter mandatory hourly-priced are a better vehicle to effectuate the Commission's policy of increasing DER penetration, while achieving greater value for consumers at decreased costs as compared to CDG.

Pace

In its reply comments, Pace states that several party comments seem to walk back the productive agreements that the collaborative reached over the last year and are counter to the progress of the collaborative effort. While Pace does not comment on the merits of the JU's modeling critiques, it does

note that the JU comments seem to underscore one of Pace's concerns with the Staff Report - that for the sake of exigency, the collaborative and Staff Report adopted existing market values as proxies for the different time and locational values that DER can provide to the grid, thus leaving a great deal of uncertainty around the actual value of DER to the grid. Pace suggests leaning toward preserving the status quo until a full analysis can be performed.

Pace disagrees with the JU proposal for a 5% of peak load cap on incremental distributed solar capacity, and claims that such a limit is not supported by any specific analysis of the bill impact at 5% incremental penetration, or the reliability concerns attendant that level of solar penetration. Additionally, Pace comments that the proposal by the JU to shorten the application of the MTC to 10 years does not reflect the life of the DER asset or the value that it will provide to the grid over that period. Pace also opposes the JU's proposal to reset the tranches and reweight them towards increasingly lower compensation levels. To do so, Pace continues, would on the whole steer a greater portion of the market towards a discounted compensation rate that is not based on actual value analysis, but merely an arbitrary, round rate of discount from current net metering compensation.

Next, Pace disagrees with the UIU proposal to require DER developers to post performance bonds. Pace avers that this recommendation is short-sighted because DER is not being compensated for the 20-year, deferred transmission and distribution value of its generation under the Phase One tariff.

With respect to the comments offered by MI, Pace disagrees with the assertion that the VDER proceeding is driven by need to replace NEM because that approach overcompensates certain DERs. Pace comments that the purpose of the VDER proceeding is not to reduce compensation to DER projects, but

instead to more accurately compensate DERs for the value they provide to the distribution system and society. Finally, with respect to the MI comments that suggest DER should not have the option to opt-out of the MTC in favor of DRV, Pace disagrees and comments that to the extent project developers wish to forego the assurance associated with the MTC in favor of developing where they can provide greater grid benefits, they should be encouraged to do so.

PULP

In its reply comments, PULP notes that many stakeholder focus on the use of non-market based support from ratepayers to promote the DER market, instead of implementing market based approaches to encourage the reliance on distributed generation. PULP opposes this approach and asserts that any proposals for ratepayer subsidies should rely on proven, documented ratepayer benefits that outweigh any subsidies. PULP also expresses concern with the analysis in the Staff Report of bill impacts on residential and other ratepayers. In light of the comments filed by the JU expressing that bill impacts may be understated in the Staff Report, PULP recommends that Staff be required to revise and reissue its Report for additional public comment and response before new ratepayer subsidies are placed before the Commission for determination. Additionally, PULP objects to the apparent approach to set an artificial level of additional ratepayer support to justify the recommendations for subsidies to DER providers and comments that the Staff Report fails to consider the cumulative effect of ratepayer increases already approved by the Commission or embedded in rate cases and other REV related proceedings.

PULP supports the UIU comments urging the Commission to adopt robust oversight and regulation policies with respect to the business practices and disclosures for certain DER

providers. Additionally, PULP agrees with the observation and concern raised by AEMA - that the Staff Report appears to forward discriminatory policies that appear to favor certain types of demand side management and other technology-based solutions in its recommended compensation methodologies. Along those lines, PULP comments that the Staff Report does not reflect market based solutions and would continue the unfair structure that favors solar programs.

Next, PULP opposes comments, mainly submitted by solar advocates, that continue to request ratepayer support for their programs and policies instead of relying on market based solutions. PULP supports ratepayer support through performance based incentives only when actual ratepayer benefits - lower rates and better service - are documented. PULP comments that including vague and unsupported "values" in any determination of what ratepayer support should be approved harms ratepayers and runs the risk of overvaluing DER.

SolarCity

SolarCity, in its rely comments to the JU initial comments, states that the JU's submission was permeated with new arguments and assertions, issues pertinent only to Phase Two, and matters that are completely irrelevant. SolarCity comments that the JU comments do not align with the efforts of the collaborative to discuss positions and substantive concerns in good faith among the stakeholders. SolarCity notes that the JU comments seem to be targets toward the final end state tariff, not the interim approach under discussion in Phase One comments. Additionally, SolarCity avers that several of the JU comments contradict the terms of the Solar Progress Partnership agreement; a joint proposal on a DER compensation mechanism framework entered into by SolarCity and other solar companies with the members of the JU. Therefore, SolarCity urges the

Commission not to rely on the arguments or evidence submitted by the JU for the Phase One Order, and instead to consider those comments in Phase Two of the VDER proceeding.

Solar Parties

In its reply comments, Solar Parties offer that the comments provided by the JU rest on inaccurate and incomplete information, and disruptive policy proposals that are counter to the goals of the proceeding. Solar Parties comment that the JU comments ignore the work of the collaborative and has the potential to derail the proceeding.

Solar Parties oppose the approach proposed by JU for determining the value of ICAP and continue to support the approach proposed in the Staff Report. Additionally, Solar Parties comment that the JU proposal for a performance-based MTC directly contradicts the purpose of the MTC and the principles upon which it is based, and thus should be rejected. Solar Parties also oppose the JU recommendations to limit the eligibility for the MTC to 10 years and to limit distributed solar in Tranche Zero and under the Phase One Tariff to 5% peak load. The JU comments, Solar Parties continue, also rely on flawed analysis of revenue impacts by, among other things: 1) understating residential revenues; 2) overstating the estimated revenue impacts from mass-market PV exports; and, 3) focusing on one downward adjustment to the VDER valuation methodology and ignoring other adjustments that would increase the values of DER.

Next, Solar parties recommend dismissing the JU's analysis of CDG profit margins as based on unfounded assumptions and flawed modeling. Solar parties also comment that the data relied on by the JU with respect to the interconnection queue has been acknowledged in the collaborative to be inaccurate and

unreliable information that cannot be reasonably relied upon to make policy determinations in this proceeding.

With respect to the comments filed by Borrego, the Solar Parties support the recommendation to implement a proxy locational value based on Central Hudson's DSIP study and the framework the Commission already established in the CDG Order. Further, Solar Parties Borrego's recommendations to leave determination of de-averaged MCOS studies to Phase Two implementation, and the recommendation to use the SC1 rate for capacity. Solar parties also share the concern expressed by Borrego the Staff's proposal would make it more difficult for projects subject to the old SIR to achieve grandfathering status as compared to more recent projects subject to the new SIR. Finally, Solar Parties urge the Commission to approve the queue management and interim cost sharing proposals alongside the VDER tariff.

TASC

In its reply comments, TASC notes its support for and concurrence with the reply comments submitted by SEIA and Vote Solar. TASC further comments that the comments of the JU are a departure from the extensive work that has been done as part of the collaborative process. Specifically, TASC notes that the circuit breaker mechanism proposed by the JU is at odds with the iterative and data-driven approach that was laid out in the Staff Report and recommends that this proposal be rejected. Finally, TASC comments that the JU greatly overstate the revenue impact of mass market exports.

UIU

In their reply comments, UIU express support for imposing a hard cap on customer bill impacts with a robust circuit breaker mechanism similar to JU's recommendation, in

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

order to limit the shifting of DER costs onto non-participating customers. UIU recommends a hard ceiling on DER mass-market projects in each utility's service territory to limit the cost shift to 2% because a hard cap with a pre-defined circuit breaker mechanism will both give the market regulatory certainty and help mitigate the rate shock to non-participants. Further, UIU comments that the Commission should adopt a conservative approach to calculating the 2% cap that limits harmful cost shifts during the development of a more accurate value stack, as opposed to the methodology proposed in the Staff Report which appears to err on the side of underestimating cost-shifts.

With respect to grandfathering of projects connected during Phase One, UIU recommends that such projects should be grandfathered for as short a term as possible to ensure customers pay the most accurate available value of DER, and supports the shorter 15 year period proposed by the JU. Additionally, UIU supports the Staff Report's cost allocation principles, but further recommends distinguishing the benefits and costs between participants and non-participants within each service class. Finally, UIU proposes addressing the concept of an LMI value adder in Phase Two.

LISTING OF INDIVIDUALS OR ENTITIES THAT SUBMITTED PUBLIC
COMMENTS

ALLAN HARARI

COMVERGE, INC.

DAIRY FARMERS OF AMERICA

DENNIS PHAYRE

ENERGY STORAGE ASSOCIATION

GRAVITY RENEWABLES

HIGH PEAKS

SOLITUDE DEVELOPMENT, LLC

SOLAR POLICY FORUM

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

STRATEGAIN, LLC

SUNRISE SOLAR SOLUTIONS

TOM KACANDES

VANGUARD RENEWABLES

PUBLIC COMMENTS

ALLAN HARARI

Mr. Harari comments that Staff's proposal perpetuates market uncertainty, especially for CDG, and that the lack of foundational data and empirical evidence further challenges the justification to transition to a new paradigm. Mr. Harari further comments that it would be more appropriate to base a transition on a percentage of operational projects as compared to state goals, such as the CES, and at the very least should extend implementation of the program to a five-year period. Mr. Harari is also concerned about thresholds for project maturity requirements and that the new paradigm may only benefit a handful of development interests.

COMVERGE, INC.

Comverge expresses concerns that Staff's proposal would result in unintended consequences. Specifically, Comverge is concerned about a crowding out of the market under Phase One as a result of the focus on NEM-eligible technologies. Comverge is also concerned about the lack of performance requirements and the overlap of market opportunity for value of "D" aspects with markets in which non-solar DER resources participate. Comverge recommends placing a specific MW cap until methodology for all DER solutions can be sufficiently developed. Additionally, Comverge recommends that DRV for purely intermittent resources be suspended until all resources are evaluated and that environmental value also be applied to DER and NWA programs to ensure a more level playing field.

DAIRY FARMERS OF AMERICA

The Dairy Farmers of America offer support for other commenters who focused on properly recognizing the benefits of anaerobic digester technology, including capturing the variable environmental value associated with this technology and that this technology offers value through destroying of carbon equivalents.

DENNIS PHAYRE

Mr. Phayre offers comments on aspects of the valuation of DER in the context of values offered to the distribution system. Mr. Phayre argues that the value of "D" should comprise not only deferred grid costs but also strategic locational values. Mr. Phayre further comments that NEM does not work well for large-commercial customers under a volumetric crediting system and that with the appropriate decisions, the Staff Proposal offers the potential to support this market segment. In particular, Mr. Phayre argues for returning to a monetary crediting system, and considering large projects as both energy producers and capacity providers.

ENERGY STORAGE ASSOCIATION

ESA offers support for the comments of NY-BEST. Specifically, ESA calls for immediate work on determining valuation and compensation for stand-alone storage systems and to also establish concrete goals or targets for the deployment of storage in New York. ESA further supports Staff's recommendation to immediately unbundle values associated with DER.

GRAVITY RENEWABLES

Gravity offers support of other commenters on the following points: that any renewable generation used for CES

Tier 1 compliance should receive environmental value and that the definition of environmental value be more inclusive. Gravity is also concerned about Staff's propose for capacity valuation and support AMP's comments in this regard. Gravity also argues for a more inclusive MTC that would be available to RNM projects.

HIGH PEAKS SOLAR

High Peaks Solar expresses concern regarding the future growth of the solar industry in New York and that the Staff Proposal will hinder the market, especially the growing CDG market. In particular, High Peaks is concerned about the recommendation to move to monetary crediting and challenges it will pose for customer acquisition and understandability.

SOLITUDE DEVELOPMENT, LLC

Solitude comments in support of the proposal to include an MTC for CDG projects as well as Staff's recommendation for environmental value. Solitude shares others concerns that moving to monetary crediting will cause customer and market confusion as well as administrative billing complexities for the utilities. Solitude offers several suggestions including options for making sure the credits are bankable and sufficient terms to support and increase project financability. Finally, Solitude recommends a MTC approach that would be weighted by utility territory as well as by load zone.

SOLAR POLICY FORUM

The Solar Policy Forum is concerned about the complexity and policy instability that they argue would result from Staff's proposal. The Solar Policy Forum argues for a 4% net utility revenue impact to establish program size and to take a much more gradual approach in moving away from NEM.

STRATEGAIN, LLC

Strategain applauds Staff's work and proposal towards a full understanding of the value of DER and the proposed move to increased granularity of values and services. At the same time, Strategain comments that they remain concerned about the final recommendations for valuation and integration of DER into the grid. Strategain also urges Staff and the Commission to consider the interconnectedness of the various REV initiatives and linkages and the need to ensure greater consumer insight and understanding into these complex decisions.

Specifically, Strategain recommends:

1. Immediately initiate a top-down, strategic renovation of REV policy reviews.
2. More accurately quantify environmental, reliability, and resiliency values.
3. More accurately quantify temporal and locational distribution values and work towards greater data collection and dissemination to the DER marketplace.
4. Align state utility pricing and revenues with utility costs.
5. Encourage the DER growth, including proper standby rates and fast & accurate interconnection procedures.
6. Promote a diverse mixture of DER technologies.
7. Staff's use of day-ahead LBMP value for energy excludes the use of DERs for dynamic grid management. Customers that want to use their DER to manage loads in the real time market or ancillary service markets should be rewarded for doing so. Staff's value stack should include this value.
8. NYSERDA research studies into the Value of DERs are peculiarly absent from Staff's report. The Commission should take steps to ensure the delivery of study and research on this topic in a timelier manner and with more impactful results.

SUNRISE SOLAR SOLUTIONS

Sunrise Solar focuses its comments on Staff's Proposal for CDG, and argues that it is unworkable in its current form. In particular, Sunrise is concerned about the move to monetary crediting and the challenges that this will present for customer acquisition and simplicity as compared to the NEM paradigm. Sunrise further comments that the 10% step-downs for the MTC are too significant given the early stages of this market segment and instead suggest step-downs of 2%. Sunrise also argues for a longer compensation term for grandfathered systems and suggests that 25 years would be more appropriate than the 20 years as proposed by Staff. Finally, Sunrise offers comments on the requirements for project maturity (i.e., 25% of interconnection costs or an executed interconnection contract), arguing that these requirements are not equivalent.

TOM KACANDES

Mr. Kacandes submits comments from the perspective of a small CDG developer. Mr. Kacandes is concerned about Staff's proposal and the uncertainty that it will bring to the emerging CDG market. He believes that if adopted as proposed, New York's CDG market will come to a halt. Specifically, Mr. Kacandes is concerned about market disruption from monetary crediting, access to market opportunity for smaller, local developers and that the Value Stack will not sufficiently support the economics of CDG.

VANGUARD RENEWABLES

Vanguard focuses its comments on the environmental value associated with DER, and recommend that the environmental value should be variable rather than fixed over the life of the projects, and that environmental value should include not only

carbon offsets, but carbon equivalents destroyed through the anaerobic digestion of manure.

PUBLIC COMMENTS FROM INDIVIDUALS

Over 2,200 individual comments were received urging the Commission to reject proposed plans to impose caps on net energy metering (NEM), and to push towards 100% renewable energy by 2035. In particular, commenters argue that NEM supports the expansion of residential clean energy and that New York State needs additional clean, distributed energy, not less. Commenters further argue that the state's NEM program should credit customers at retail electricity rates and should not impose any surcharges.

Over 700 individual comments were received expressing concern about the Staff proposal, which commenters characterize as reducing the compensation for CDG energy. Commenters argue that the proposals undermine NEM, which they argue is one of the most basic foundations of renewable energy policy and energy democracy, especially for enabling access for LMI customers. Commenters further argue to maintain NEM, for at least the next two years, as a simple form of compensation, and to reject the new proposals. Commenters suggest that the Commission should account for all the benefits that renewable energy provides including values not accounted for on the Staff proposal including: reduced air pollution, reduced water usage, new jobs, lower and stabilized energy bills, storm resilience, and energy independence. Lastly, commenters argue that the proposed policy changes are confusing and complicated, and will significantly impair this important market.

Over 200 individual comments were received in support of expanding access to solar energy for New York State residents through CDG. Commenters urge the Commission to design the proposed program in a way that supports products and services

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

that are on par with that of rooftop solar. Commenters further argue for a program of sufficient size in order to ensure maximum participation as possible.

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

March 9, 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 Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, 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 development of and prompt transition to more accurate valuation and compensation mechanisms for Distributed Energy Resources (DER), particularly distributed generation (DG) projects currently compensated through Net Energy Metering (NEM). The transition involves new compensation methods based on new tariff provisions. To effectuate this transition, NEM-eligible DG projects not interconnected into the utility grid as of the date of the order will receive compensation based on new tariff provisions developed in Phase One of the Value of Distributed Energy Resources (Value of DER or VDER) proceeding. Projects interconnected as of the date of the order will

continue to receive NEM compensation unless and until the project owner chooses to opt-in to a new compensation methodology.

During an initial period, new projects will continue to receive compensation based on NEM methodologies, except that those projects will be limited to receiving such compensation to 20 years before transitioning to new compensation mechanisms.

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).