STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

WHITEPAPER REGARDING FUTURE VALUE STACK COMPENSATION, INCLUDING FOR AVOIDED DISTRIBUTION COSTS

December 12, 2018

INTRODUCTION

On July 26, 2018, Department of Public Service Staff (Staff) filed two documents: a Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (Draft DRV Whitepaper) and a Staff Whitepaper on Future Community Distributed Generation Compensation (CDG Whitepaper). Staff requested comments on the Draft DRV Whitepaper by August 27, 2018 and on the CDG Whitepaper by October 15, 2018. Subsequently, a notice of the CDG Whitepaper was published in the State Register consistent with the requirements of the State Administrative Procedure Act, with comments pursuant to that notice due by October 22, 2018. Staff explained in the Draft DRV Whitepaper that a final Whitepaper would follow for formal comment and Commission consideration.

Following review of comments from stakeholders on the Draft DRV Whitepaper, Staff determined that several changes were appropriate to the recommendations therein. Furthermore, on further analysis of the CDG market and review of comments on the CDG Whitepaper, Staff developed several additional recommendations related both to compensation for avoided distribution costs and future CDG compensation. In this final Whitepaper Regarding Future Value Stack Compensation, the recommendations from the Draft DRV Whitepaper have been modified and are followed by a paragraph explaining the modifications. In addition, further recommendations on CDG compensation have been added in a new section. The "Background" and "Summary of Stakeholder Views" Sections have not been edited.

Staff recommends that the full set of proposed changes in this Whitepaper, as well as the recommendations in the CDG Whitepaper and in a separate whitepaper filed today regarding Capacity Value (Capacity Whitepaper), be taken up by the Commission simultaneously so that all modifications to Value Stack compensation happen at the same time. In advance of Commission consideration, Staff requests stakeholder comments on these recommendations by February 25, 2019.

BACKGROUND

On March 9, 2017, the New York State Public Service Commission (Commission) issued an Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Transition Order). The VDER Transition Order directed that the compensation for eligible distributed energy resources (DERs) transition from net energy metering (NEM) to the Value Stack. The Value Stack is a methodology that bases compensation on the actual, calculable benefits that such resources provide. Quantifying and compensating these benefits remains central to the Commission's overall strategy to move to an energy system that is cleaner, more affordable and increasingly resilient. Equally as important are the objectives of creating robust and competitive markets for DER that are sustainable over the long-term, and can maximize value and opportunity for society, the electric grid, and consumers.

DERs subject to the Value Stack receive compensation for the energy they inject into the utility system for a set of values calculated based on the utility costs they offset: Energy Value, based on the energy commodity purchase offset by each kWh injected; Capacity Value, based on the ICAP purchase offset by injections; Environmental Value, based on the Clean Energy Standard (CES) compliance cost offset by each kWh injected; Demand Reduction Value (DRV), based on the distribution costs offset by injections, averaged across the utility's service territory; and Locational System Relief Value, (LSRV), available only in locations that the utility has identified as having needs that can be addressed by DERs, and based on the higher, specific distribution costs offset by injections in that area. Mass market customers participating in Community Distributed Generation (CDG) projects do not receive the DRV; instead, they receive the Market Transition Credit (MTC), an additional value designed to moderate the transition from net metering to the Value Stack.

For decades, the New York Department of Public Service has relied on utility marginal distribution capacity cost studies to estimate incremental/avoidable costs associated with Energy Efficiency (previously called Demand Side Management or DSM) measures, in rate design deliberations, and, in more recent years, in designing demand response programs. In the VDER Transition Order, the Commission directed that these studies be used as the basis for identifying and calculating DRV and LSRV. The utilities were ordered to "de-average" these general marginal cost estimates by identifying LSRV areas, as well as LSRV values and capacity limits for those areas, and then calculating DRV by combining the costs not included in the calculation of an LSRV. This produced a $/kW-year value for each LSRV and for the DRV in each utility. In order to tie compensation to a relevant measure of resource performance, these values were allocated to the ten highest annual load hours for each utility; that is, the $/kW-year value is divided by ten to create a $/kWh value that resources earn for each kWh generated during those ten peak hours of the year. This credit is calculated annually, divided by twelve, and credited monthly. Table 1 contains the DRV values currently reflected in each utility's VDER Tariff.

Table 1. DRV Values per kW-Year and per kWh, for Top Ten Load Hours

	DRV					
	CHGE	O&R	NGRID	NYSEG	ConEd	RGE
$/kW-Yr	$6.00	$64.78	$61.44	$29.67	$199.40	$31.92
$/kWh--10	$0.60	$6.48	$6.14	$2.97	$19.94	$3.19

The VDER Transition Order, including the Value Stack, has successfully encouraged the development of a large number of CDG projects designed to serve mass market customers. As noted, instead of compensation for DRV, these projects are eligible for an MTC as a transitional mechanism for in the move to VDER. However, in absence of an MTC value, developers have experienced difficulty planning projects where the DER is intended to serve a single large commercial customer whether onsite, through remote net metering, or as an anchor tenant in a CDG project. As these projects are not eligible for the MTC, it is prudent to consider the efficacy of DRV and its impact in creating a financially viable Value Stack tariff. A number of developers and other stakeholders have observed that the DRV and LSRV mechanisms are lacking the necessary certainty and predictability to structure projects under VDER policy that are not eligible for the MTC. In addition, some stakeholders have submitted specific critiques regarding technical aspects of the utility marginal cost studies, which provide the basis of those values.

The technical methods used in the utility marginal cost studies are not addressed in this Whitepaper for several reasons. Most significantly, as noted above, utility marginal cost studies are used for many purposes in addition to VDER compensation. For that reason, the technical aspects of distribution marginal cost estimation should be reviewed in a more generic setting. Further, these marginal cost study methodologies have been developed over many years and are being improved continuously. Staff agrees that continued improvement – and indeed planned and focused improvement – of marginal cost studies is a necessary and critical aspect of hastening the transition to an increasingly distributed grid. However, the appropriate forum for that improvement and associated deliberations is as part of utility Distributed System Implementation Plan (DSIP) filings. Utility DSIP filings include substantial discussion of utility costs and system data, particularly capital investment plans (driven largely by expected load growth) which are direct inputs to the marginal cost studies. Given that a new set of utility distribution marginal cost studies were filed on July 31, 2018, in conjunction with utility DSIP filings, Staff recommends that, starting with those 2018 filings as a jumping off point, the biennial DSIP process be used as the primary venue for the review and improvement of these distribution marginal cost studies and other aspects related to quantifying distribution value associate with DER. For that reason, Staff will not conduct substantive review of the critiques of existing marginal cost studies in this document. Rather, a process for reviewing these studies will be developed in the context of the DSIP filings. Staff will ensure that all members of the Value Stack working group, as well as other interested stakeholders, have an opportunity to participate fully in this process and, following the process, to provide continued input on the appropriate use of the utility marginal cost studies for determining avoided distribution cost compensation.

This Whitepaper will instead focus on addressing aspects related to the function of the DRV and LSRV as compensation mechanisms for DERs, particularly large on-site projects and remote crediting projects.

SUMMARY OF STAKEHOLDER VIEWS FROM WORKING GROUP DISCUSSIONS

Through the Value Stack working group, Staff has worked with stakeholders to develop a common understanding of the marginal cost studies and to allow stakeholders to explain and discuss views, criticisms, and proposals related to the DRV and LSRV. Stakeholders also had the opportunity to make presentations and filings regarding their proposals and to respond to each other's proposals. This section briefly summarizes some of the issues discussed and proposals and responses made, focusing on those concerns and proposals that Staff recommends addressing at this time. The Value Stack working group is now also considering recommendations regarding refinements to the Environmental Value and proposals resulting from that process will be separately presented for more formal consideration later this year.

Some stakeholders posit that providing full marginal cost compensation to intermittent resources overcompensates these resources, inasmuch as they are not providing the specific, granular functionality and performance required to substitute for the utility investments upon which the marginal cost studies are based. By comparison, dispatchable resources are potentially able to meet these requirements but, some stakeholders believe, the DRV and LSRV mechanisms lack the commitment and control mechanisms necessary to allow utilities to consider them fully reliable. Further, it is argued, the Phase 1 approach is not coordinated well with other methods of compensating distributed resources for avoided distribution costs, specifically Non-Wires Alternative (NWA) solicitations and retail demand response (DR) programs.

Other parties have argued that the DRV and LSRV mechanisms are too complicated, unpredictable, and uncertain to support the development of many DER projects, such that developers and investors often significantly or entirely discount these values, thereby undermining the value proposition for a potential DER providers. In particular, they explain that the updating of DRV rates every three years, based on new marginal cost studies and without any guarantee as to the size of potential changes, means that the DRV rate cannot be used to plan for and secure investment for long-term assets. Furthermore, particularly for solar photovoltaic (PV) generators – which represent the vast majority of VDER resources – PV providers observe that using performance during each year's top ten load hours, determined after-the-fact to calculate compensation, results in a value stream that is too speculative for a PV developer to rely upon when deciding whether to incur any incremental investment to try to capture such value, as both the hours themselves and the generator's performance during those hours can be unpredictable. These stakeholders submit that most of the value-impacting decisions for PV are made at the time of planning, development, siting, and installation. While these decisions, such as orientation of the panels or use of trackers, can impact the generator's performance during peak hours in general when faced with a performance window of ten hours over the course of a year, the risk of underperformance due to factors like weather is too great to justify the investment that would otherwise result in added distribution value and therefore project compensation. This problem is exacerbated, it is argued, when the top ten hours differ by network within a utility territory, as it does in Con Edison's VDER tariff. Further, the argument continues, utility planning and investment (and thus avoidable distribution cost) is based on a multi-year forecast of future network peak load, not on any one year's actual top ten hours.[1]

Another concern raised was that, given the time constraints in Phase 1, the methods for "de-averaging" DRV value from LSRV value were more heuristic than sophisticated. Also, some parties felt that the method for determining the MW limits for each LSRV area was not sufficiently transparent.

[1] This is particularly true in a year that has very mild weather and de facto peak hours that happen to differ from those in a more typical year.

In addition, some stakeholders expressed that the Value Stack compensation mechanism is not entirely well suited for customers seeking only to offset their usage with local generation, and that the DRV and LSRV components cause particular difficulty in developing such projects.

RECOMMENDATIONS RELATED TO DRV AND LSRV, AS MODIFIED

Considering all of the above, Staff believes that the current DRV and LSRV rules may represent an attempt to achieve greater granularity and precision than is reasonable under VDER Phase One and possible in an open, administratively-determined tariff mechanism. The desire to compensate for precise grid values must be balanced with the risk that a more sophisticated tariff may result in price signals that do not fully incentivize and motivate developers and customers to make decisions based on the objective of maximizing grid value.

In more competitive markets, the granularity and specificity required to meet particular, specific functional needs[2] is usually managed with individual procurements and contracts, rather than through generic commodity markets. The DSIP process has made significant progress in addressing many of these same issues in the context of specific NWAs, through which utilities employ market-enabling procurements with detailed functional requirements to offset the need to make particular distribution system investments. In Staff's view, the VDER tariff should be a supplement to, not an imitation of, the integrated planning, investment, and contracting process developed through the DSIP process and NWAs. However, Staff also recognizes that during this period of transformation through which the grid is becoming increasingly distributed and bi-directional and DER technologies more prolific, there is value to continuing a tariff-based process for smaller, intermittent facilities that cannot economically participate in utility NWAs given their unique characteristics and market segments. When optimally designed and located, these resources will continue to allow utilities to avoid a certain amount of future infrastructure investment[3] and related O&M, and therefore it is appropriate a tariff-based mechanism to compensate for that. For those reasons, Staff proposes a change to the Value Stack distribution

[2] Especially with respect to long-lived assets, such as the avoided distribution investments that DRV and LSRV are intended to reflect.

[3] At least for as long as consumption load continues to grow and remains significantly greater than the DG injection load on the system. In the future, as DG penetration increases, increasing injection load at certain points in the system may lead to infrastructure cost onsets rather than offsets.

value compensation in order to leverage the strengths of a tariff-based mechanism for these resources. At the same time Staff observes that DSIP, NWAs, and DR programs will continue to serve as a valuable method for encouraging and compensating responsive resources, such as dispatchable generators, more surgically and with greater precision.

Modified DRV Calculation and Compensation

To design a more predictable and reliable version of the DRV under VDER Phase One, Staff reviewed other mechanisms for estimating distribution system value. Ultimately, the contribution made by injections into the system by VDER resources is likely to be similar, on a $ per peak kW per year basis, to the contribution provided by the portfolio of Energy Efficiency (EE) resources. Thus, Staff proposes replacing the “de-averaged” DRV with the system-wide marginal cost estimates used generically for each utility’s EE benefit-cost calculations. The DRV in the Value Stack tariffs would be updated no more frequently than every two years, as opposed to the current annual update, consistent with the DSIP cycle, following the review and input process established for the biennial marginal cost study filings, discussed above. These $/kW-year values used to calculate the DRV would be the same system-wide values used for evaluating EE programs. The chart below shows the resulting proposed starting $/kW-year values:

Central Hudson	$14.55
Consolidated Edison	$226.00
National Grid	$66.48
NYSEG	$30.84
RG&E	$31.58
O&R	$70.00

Staff recommends that projects that qualify[4] after July 26, 2018, the date of publication of the Draft DRV Whitepaper, receive DRV compensation based on a new methodology using this $/kW-year value. The proposed new methodology, which is described in the following paragraph, will provide a more predictable and reliable DRV and thereby improve the ability of the DRV to spur development of large on-site and remote projects and to encourage design of those projects to maximize system benefits.

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

Staff proposes that, under the new methodology, the total $/kW-year would be assigned as $/kWh to the peak summer hours of 1:00 PM to 6:00 PM on non-holiday weekdays from June 24 through August 31. This will result in DRV compensation being spread over either 240 or 245 hours each year. These are the same hours that are proposed to be used for Capacity Value Alternative 2 going forward; they represent the summer hours that are the most likely to be candidates for the peak summer load hour.[5] This compensation methodology would increase predictability by providing advanced knowledge of the specific hours and, as it spreads compensation over many more hours than the current 10-hour methodology, substantially reduce the uncertainty resulting from a small number of hours due to factors like weather. At the same time, it would compensate a project for its performance during the overall set of hours that drives utility peak needs. One benefit of this approach is that it could induce PV systems to add solar tracking devices to their systems. To allow the $/kW-year to shift to reflect changing needs without creating an unreasonable degree of uncertainty, Staff proposes that this alternative provide stability in a manner associated with traditional tariff revisions, by limiting how much the tariff value can change at each potential reset.[6] As the base value would change every two years, as described above, the $/kWh would also change to follow that shift, but would be subject to a maximum adjustment of 5% in any direction in each two-year period. Therefore, while the precise $/kWh for the 25-year Value Stack compensation period would not be known in advance, an upper and lower bound would be easily determinable. Another benefit of this approach is that it would not require tracking and compensating future VDER resources by vintage, as all eligible resources would be compensated based on the current DRV regardless of their year of interconnection. Under this proposal, the $/kWh during the relevant hours would start at the $/kw-year listed in the table above divided by the number of relevant hours (240 or 245, depending on the year); that $/kWh will then be adjusted by up to 5% up or down when

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[5] Staff believes that this set of hours matches reasonably well, and better than the 460 hours previously used for Alternative 2 Capacity compensation, with utility system peaks across utilities with the exception of the areas of Con Edison's service territory where the Commercial System Relief Program hours are 4:00 PM to 8:00 PM or 7:00 PM to 11:00 PM. Commenters should offer suggestions on whether the 240 or 245 hours used for DRV payments in those areas should be 4:00 PM to 9:00 PM on the relevant days rather than 1:00 PM to 6:00 PM. Information on those areas is available here.

[6] Sometimes referred to as "gradualism" in tariff setting.

modified MCOS results come into effect, with further adjustments up to 5% every two years in the future.

Projects, such as dispatchable resources, that prefer a smaller number of hours with a call signal should be permitted to opt out of receiving DRV and instead participate in the utility Commercial System Relief Program (CSRP). The CSRPs are demand response programs that compensate resources for performing during an event, which is preceded by a call signal 21-hours in advance. CSRP events are called when a system is forecasted to near 90 percent of its rated capacity. Resources are compensated for their performance during the event. Utilities will need to modify the rules of their CSRPs to permit resources to perform by injecting electricity into the distribution system, as the current rules are designed only for resources that reduce load, and make any other necessary changes to permit resources that receive the Value Stack to participate in a CSRP rather than receiving a DRV as part of the Value Stack. As with other resources that participate in the CSRP, Value Stack resources will receive monetary compensation for CSRP performance, rather than compensation through bill credits.

While projects that have already qualified arguably should be grandfathered under the rules in place at the time they qualified, Staff recommends that existing DERs be permitted to opt into the new DRV alternative proposed above or CSRP participation. As with the existing DRV rules, only customers not receiving an MTC are eligible for DRV compensation.[7]

Modifications to Recommendation

Several changes were made to this recommendation in response to comments and Staff consideration. First, Option 2 was eliminated and replaced with the ability of projects receiving Value Stack compensation to participate in CSRPs. This permits the leveraging of an existing, well-functioning program rather than the creation of a new program, promotes consistency across utility activities, and allows developers considering their options to look at the history of CSRPs to understand

Second, the time period for the new default DRV compensation methodology was modified from 460 hours to approximately 240 hours, by removing weekends, July 4, and the first several weeks of June, and shifted from 2:00PM to 7:00PM to 1:00PM to 6:00PM. Staff recommends the same modification to Capacity Value Alternative 2 in the Capacity Whitepaper.

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[7] As discussed below, customers receiving the newly developed Community Credits will be eligible for DRV compensation.

As more fully explained in the Capacity Whitepaper, this will improve the alignment of price signals with system needs while still ensuring that a sufficiently large number of hours is used to ensure predictable compensation. In addition, as requested by a comment, Staff clarifies that (a) the $/kW-year used to calculate the starting DRV will be based on the MCOS studies used to calculate the original 10-hour DRV and the first update will be a change of no more than 5% from that starting DRV once new MCOS studies are approved; and (b) the full $/kW-year identified by the MCOS process will be used to determine the $/kWh compensation for the approximately 240 hours, without any reduction based on assumed or estimated coincidence. Finally, a footnote was added regarding potential differentiation of those hours in Con Edison's service territory.

Sunsetting of LSRV

Neither of the DRV alternatives proposed above provides shorter term, above-average price signals for temporarily congested networks, as the LSRV currently does. As noted above, under Phase One it has been difficult to design a simple, stable tariff that also ties compensation to location-specific functional and performance needs. The DSIP process, related NWAs, and the DR programs are proving to be the more effective tools to address this more complex set of problems and value. By contrast, the above alternatives, effectuated through a tariff-based approach, serve to recognize all of the projects used in utility marginal cost studies in order to produce a long run, stable value that, in essence, comprises both distribution values associated with DRV and LSRV, spread over time and across the entire service territory. For those reasons, the LSRV should be phased out, with any existing qualified projects continuing to receive an LSRV for the 10-year term; no new projects would be eligible for an LSRV. Any projects that can provide the specific functionality and performance requirements of either NWA or DR programs will continue to be eligible to participate in those opportunities to receive compensation for the grid value they can provide. The utilities should be required to permit resources receiving Value Stack compensation to participate in such programs, though in general this will require that those resources forego DRV compensation. Staff will also continue to work with utilities and stakeholders, through the DSIP process and other mechanisms, to develop additional mechanisms of identifying and providing price signals and compensation for distribution system needs.

Modifications to Recommendation

This recommendation was modified based on stakeholder comments to further clarify that resources receiving Value Stack compensation may also participate in programs that offer compensation based on local distribution values, such as demand response programs and non-wires alternatives, and to state that Staff will continue to work with the utilities and stakeholders to identify other methods of identifying and providing compensation for local distribution values.

Phase One NEM for Certain On-Site Projects

Staff recognizes that the Value Stack is a new compensation model, which as it evolves, may not be well-suited for use in all cases and market segments. For instance, the Commission extended Phase One NEM to all on-site, mass market DER projects installed before January 1, 2020. Staff was also directed to work with stakeholders to develop rate design proposals that would support consideration of a new compensation mechanism for these mass market projects after January 1, 2020. The continuation of Phase One NEM under VDER is, however, limited to residential and small non-residential customers, which are defined as "non-demand metered" commercial customers thus excluding all demand-metered non-residential customers. Given the transitional nature of VDER Phase One, it is prudent to reflect on the viability of opportunities under VDER policy for smaller demand-metered non-residential customers that desire to offset their own usage with on-site DER technologies. Accordingly, Staff believes it is appropriate to extend Phase One NEM to these customers in order to encourage greater participation and investment in DER across all customer segments. Specifically, Staff proposes that Phase One NEM be available for projects that (a) have a rated capacity of 750 kW AC or lower; (b) are at the same location and behind the same meter as the electric customer whose usage they are designed to off-set; and (c) have an estimated annual output less than or equal to that customer's historic annual usage in kWh. This will apply at a minimum to all projects that qualify before January 1, 2020, for a 20-year term from each project's in-service date. Further, as these customers are, by definition, already subject to demand rates, Staff will consider whether this category of Phase One NEM should continue for new projects or should be modified as part of making its recommendations regarding a post-January 1, 2020 successor tariff for on-site mass market DG customers.

Modifications to Recommendation

This recommendation was not modified. Most commenters supported this proposal. While one commenter expresses concern that this is a step backwards and could increase costs to non-participants, Staff maintains that it is consistent with the VDER proceeding's focus on injections, rather than energy consumed behind the meter, and that any resulting cost shifts will be minimal, as the demand metered customers who will be newly eligible for Phase One NEM have volumetric rates that are much more aligned with utility costs than non-demand-metered customers. In contrast, extending this recommendation to remote net metering, as another commenter recommends, would be inconsistent with the goals of this proceeding and could result in more significant cost shifts.

NEW RECOMMENDATIONS

Replacement of MTC with Community Credit for New CDG Projects and DRV for All Customers of New CDG Projects

Based on stakeholder input and further analysis, Staff modifies and replaces its recommendation in the CDG Whitepaper that Tranches 5 and 6 be established in New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), and Rochester Gas and Electric Corporation (RG&E) with MTCs of $0.03/kWh and $0.025/kWh respectively. Instead, projects in those utility territories qualifying after July 26, 2018[8] should receive a Community Credit of $0.0225/kWh. The Community Credit will differ from the MTC in that all members of the CDG project will receive it, rather than only mass market customers, and in that recipients of the Community Credit will also be eligible to receive DRV compensation. Eligibility for the Community Credit will be limited to projects in each service territory equal the number of MWs proposed in that territory for Tranches 5 and 6 in the CDG Whitepaper: 110 MW in NYSEG, 525 MW in National Grid, and 75 MW in RG&E.

The Community Credit will serve several purposes. It will encourage the inclusion of one or more large customers, often called anchor customers, in CDG projects. The presence of an anchor customer in a CDG project reduces the financing and customer acquisition costs of that CDG project; it may also allow that CDG to have less stringent credit requirements for other customers. Because it lowers CDG project costs, the Community Credit can be lower than the MTC and still ensure that projects are viable, potentially resulting in lower net revenue impacts and therefore lower impacts on non-participating ratepayers. As the Community Credit is lower,

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[8] Consistent with the CDG Whitepaper, Staff recommends that these changes apply to projects that qualified after the date the CDG Whitepaper was filed, July 26, 2018.

it can also be paired with the DRV. This means that CDG projects will have the same incentive as other projects to design and operate their systems to maximize their receipt of the DRV, which will also maximize benefits to the utility system. The requirement that 60% of a CDG project's output be dedicated to small customers will ensure that most of the benefit of each CDG still goes to residences and small businesses. While the institution of the Community Credit will provide an incentive for large customers to receive solar credits from a CDG project rather than from a dedicated remote crediting project, Staff believes the overall benefits provided by the presence of an anchor customer in CDG projects justifies this distinction. Furthermore, maintaining the MW levels proposed in the CDG Whitepaper while instituting a Community Credit below the proposed MTC levels will ensure that non-participating ratepayers also benefit from the institution of the Community Credit, with estimated net revenue impacts below the approximately 2% levels that would have resulted from the CDG Whitepaper's recommendations. The establishment of a level Community Credit and DRV applicability across utilities will also improve the simplicity of Value Stack compensation for new projects.

This recommendation only applies to projects in NYSEG's, National Grid's, and RG&E's service territories. With respect to Orange and Rockland Utilities, Inc. (O&R) and Central Hudson Gas and Electric Corporation (Central Hudson), Staff maintains the recommendation from the CDG Whitepaper that new projects in their service territories receive only the base Value Stack as compensation, with an additional up-front incentive, and with all customers receiving the DRV. For new projects in the Consolidated Edison Company of New York, Inc. (Con Edison) service territory, Staff retains the CDG Whitepaper's primary recommendation, for a revised Tranche 1.1 with an MTC of $0.1435 applicable only to mass market customers and therefore the DRV applicable only to non-mass-market customers. However, once the 128 MWs allocated to the revised Tranche 1 are exhausted, Con Edison should be moved to the Community Credit model, with a Community Credit to be determined, in a Staff filing based, at a level that maintains the 2% limit on incremental net revenue impact and that reflects the high level of the DRV in Con Edison.

<u>Community Credit for Anchor Customers of CDG Projects in Tranches 1-4</u>

The potential to lower project costs, and therefore increase participant benefits, while also lowering net revenue impacts, and therefore reducing non-participant impacts, also exists for CDG projects that have already been assigned a Tranche. Allowing non-mass-market customers that participate in those projects to receive a Community Credit at a level below the applicable MTC will encourage increased use of anchor customers, reducing project financing costs, while also lowering total compensation of those projects, reducing net revenue impacts. Staff believes that one unified Community Credit value across all CDG projects in Tranches 1-4 and utilities is appropriate based on the purpose of the Community Credit. In addition, the value for CDG projects in Tranches 1-4 should be lower than the Community Credit value for new CDG projects because projects in Tranches 1-4 receive higher MTC compensation for mass market participants. Based on analysis by Staff and NYSERDA, Staff proposes a $0.01/kWh Community Credit value for non-mass-market participants of CDG projects in Tranches 1-4, to be applied in the same way and for the same period of time as the MTC for those projects. This recommendation applies to all CDG projects receiving the Value Stack and qualified for Tranche 1, 2, 3, or 4 in all utilities; it does not apply to projects receiving NEM or Phase One NEM (i.e., Tranche 0 projects), nor does it apply to new O&R and Central Hudson projects.

As an example, for a project that qualified for NYSEG Tranche 2 and has 60% of its energy allocated to mass market customers and 40% allocated to large anchor customer, the mass market customers would receive the NYSEG Tranche 2 MTC ($0.0259/kWh), while the anchor customer would receive a $0.01/kWh Community Credit, and the DRV would be applied to 40% of the project.

Improvements to Capacity Value

The Capacity Whitepaper, released along with this Whitepaper, recommends modifications to the method of calculating the Capacity Value for Capacity Alternatives 1 and 2 to increase consistency and transparency. It also recommends that Alternative 2 be modified to provide compensation during approximately 240 summer hours, as described with respect to DRV Option 1 above, rather than during 460 summer hours. The changes in the Capacity Whitepaper should be considered together with the changes in this Whitepaper so that all modifications to Value Stack compensation happen at the same time.

CONCLUSION

The results of the modifications proposed in this Whitepaper, by project type and vintage, are summarized in a table in Appendix A. The proposed modifications in this Whitepaper will improve the ability of the Value Stack to provide appropriate price signals and compensation so that developers and customers design and invest in projects that provide benefits to the electric distribution grid. They will also result in the development of hundreds of MWs of additional CDG projects in New York state at a lower non-participant impact than previously forecasted. In advance of Commission consideration, Staff requests stakeholder comments on these recommendations by February 25, 2019.

APPENDIX A:
SUMMARY OF PROPOSED DRV, MTC, AND COMMUNITY CREDIT APPLICABILITY

Project Type	Compensation Methodology	MTC or Community Credit for Mass Market Customers	Community Credit for Other Customers	DRV Applicability	DRV Compensation Methodology
NEM or Phase One NEM (On-Site, RNM, or CDG)	Net Metering (Projects may opt into Value Stack)	N/A	N/A	N/A	N/A
CDG (Tranche 1, 2, 3, or 4)	Value Stack	Per Tranche	$0.010	Non-Mass Market Customers Only	Choice of 10 Hours, 240 Hours, or CSRP
CDG (New Tranche in Grid, NYSEG, or RGE)	Value Stack	$0.0225	$0.0225	All Customers	240 Hours or CSRP
CDG (O&R or CHGE post-Tranche 4)	Value Stack	None	None	All Customers	240 Hours or CSRP
On-Site (750 kW or less AC)	Net Metering (Projects may opt into Value Stack)	N/A	N/A	N/A	N/A
New On-Site (>750 kW) or Remote Crediting (Not eligible for NEM or Phase One NEM)	Value Stack	N/A	N/A	All Customers	240 Hours or CSRP