December 5, 2016

VIA ELECTRONIC FILING

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Burgess:

The Advanced Energy Economy Institute (AEEI), on behalf of Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), the Northeast Clean Energy Council (NECEC), and their joint and respective member companies, submit for filing these comments in response to the *Notice Seeking Comments on the Staff Report and Recommendations in the Value of DER Proceeding*, dated October 28, 2016, in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Vice President, Industry Analysis

Comments on the Staff Report in the Value of Distributed Energy Resources Proceeding (Case 15-E-0751)

Advanced Energy Economy Institute
Alliance for Clean Energy New York
Northeast Clean Energy Council

Preface

The mission of Advanced Energy Economy Institute (AEEI), the charitable and educational organization affiliated with Advanced Energy Economy (AEE), is to raise awareness of the public benefits and opportunities of advanced energy. As such, AEEI applauds the New York Commission for its continued commitment to the Reforming the Energy Vision (REV) and related proceedings, which seek to unlock the value of advanced energy so as to meet important state policy objectives and empower customers to make informed choices on energy use, for their own benefit and to help meet these policy objectives.

In order to participate generally in the REV proceeding and respond specifically to the Commission's October 28, 2016 *Notice Seeking Comments on the Staff Report and Recommendations in the Value of DER Proceeding*, AEEI is working with AEE and two of its state/regional partners, the Alliance for Clean Energy New York (ACE NY) and the Northeast Clean Energy Council (NECEC), and the three organizations' joint and respective member companies to craft the comments below. These organizations and companies are referred to collectively as the "advanced energy community," "advanced energy companies," "we," or "our."

AEE is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable. ACE NY's mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast. Its mission is to accelerate the region's clean energy economy to global leadership by building an active community of stakeholders and a world-class cluster of clean energy companies.

Introduction and Summary

AEEI, ACE NY, and NECEC first want to thank the Commission and Staff for the open and inclusive stakeholder process that preceded this Report. We appreciate the hard work of Staff to maintain a professional and collaborative environment throughout these discussions. And while we are mostly pleased with the outcome of this Report, as a coalition representing a diverse range of technologies, there are some issues that are of concern to us, particularly surrounding the uneven treatment of different technologies and how behind-the-meter benefits of distributed energy resources (DER) are treated.

Technology Neutrality

The Phase One methodology outlined in the Report describes efforts to develop a compensation mechanism for distributed generation (DG) that is based on performance rather than by technology type. This makes sense as the needs of the grid do not change based on the type of technology that is providing the services, and compensation should attempt to accurately price the services needed (including environmental and societal benefits) so that technologies can compete on delivering those services. We see performance-based compensation as a cornerstone of REV and as an important step in growing the market for DER. With the right compensation mechanisms in place, DERs will, over time, evolve to better align their services with grid needs and thus capture higher revenues by providing benefits better aligned with needs.

Yet there are some key differences in how different technologies are treated in the Phase One methodology, which may impact the ability of technologies to compete on a level playing field. We acknowledge the desire of the Commission to focus on a near-term methodology, and Staff, in their interpretation of that, have focused initial ratemaking reforms to compensation for community DG, remote net metering, and large onsite generation, with an eye toward solar compensation in each of those categories. Solar represents the bulk of DG in New York, and will likely remain the leader in terms of new DG capacity in the near future, so we understand the need for the Commission's focus. We also understand that the desire to reform retail net metering has resulted in a focus on solar, but that focus should not detract from the central purpose of this proceeding, namely to "develop accurate pricing for DERs that reflects the actual value DERs create."[1] Throughout the proceeding, Staff and numerous stakeholders have acknowledged the need to address other technologies, and we urge the Commission to incorporate flexible Distributed Energy Resources, including stand-alone energy storage, clean dispatchable generation, demand response, and demand side management more broadly, in a timeline that is far shorter than is expected for the Phase Two methodology. This is particularly important for the

[1] Staff Report, Page 4

technologies that had been receiving support under previous NYSERDA programs that were phased out with the expectation that these technologies would be compensated through "LMP+D," which was envisioned to be technology neutral and comprehensive of its accounting of grid and societal benefits. But since the Phase One proposal falls far short of that mark, these technologies now face a gap until a fully-inclusive compensation mechanism is developed, presumably in Phase Two.

Although we acknowledge the concern about disrupting well-established markets and businesses, the Staff proposal creates a disparity between how different types of solar projects are compensated – compensation for community solar projects is expected to decrease while net metering for on-site mass market solar will continue in place for some time.

Financeability

The Phase One compensation methodology makes key accommodations in the interest of gradualism to allow the market to adjust to performance-based compensation. Companies and markets need time to adapt and increase their confidence in these new methods for determining revenue. Building this confidence is essential for financing to be obtained and for projects to continue to be built, but this transition to performance-based compensation is happening much more abruptly for some technologies than for others. CDG projects will receive a Market Transition Credit (MTC) that provides a known level of compensation for this component of the value stack. This will allow those projects to receive financing at a lower cost than projects that are ineligible for the MTC that will instead receive the Demand Reduction Value (DRV). The DRV is based on Marginal Cost of Service values, which will fluctuate yearly. This methodology is new and the revenue that it provides will in the beginning be heavily discounted if not entirely "unbankable."

Treatment of Benefits from Self-Consumption

As we have expressed throughout the proceeding, we remain concerned about how generation that is produced and consumed behind the meter is being valued in the Phase One methodology. The current proposal assumes that the retail rate provides sufficient compensation for benefits related to energy and demand reductions behind the meter. However, in doing so, it 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. The values of avoiding emissions and future utility costs are *incremental* to retail rates. Retail rates, whether volumetric or based on non-coincident peak demand, do not value reductions at system peak differently from reductions that take place when demand is low, despite the fact that reductions at peak can reduce future costs. Similarly, clean generation that causes reductions in energy imports from the utility is of higher value than conventional (pollution producing) generation that reduces imports from the utility in the same way, but this value is not recognized in the Phase One methodology because there are no RECs generated or compensation provided for clean generation that is produced and consumed behind the meter. This appears to go against established treatment of CES-eligible technologies that previously were able to sell RECs into the Main Tier of the RPS. Additionally, behind the meter generation creates system benefits including, among others, avoided line losses, avoided T&D investments, and avoided O&M. Therefore, we reiterate our position that avoidance of the retail rate through self-consumption does not adequately compensate such DER resources for these values, and urge the Commission to consider applying the DRV and LSRV to all BTM generation regardless of whether it is consumed behind the meter or exported.

Take for example a situation where one customer on standard demand rates uses a diesel generator to manage its non-coincident peak demand charges and a second customer on the Phase One tariff that installs a small solar array with energy storage that is dispatched coincident with system peaks. Also assume neither customer ever exports energy because all generation is consumed behind the meter. In this scenario, the customer that dispatches its diesel generator to manage its peak demand would likely do *better* than the second customer dispatching its solar+storage to meet system peaks. In this case, the first customer would realize savings from reducing its demand charges with polluting generation while the second customer would neither be compensated for the emissions reductions it provides nor for the capacity relief it is providing to the system. The solar+storage customer might receive a reduction in its demand charges, but only on the off chance that the customer's peak demand is coincident with system demand. 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, and we urge the Commission to address these critical deficiencies in its order.

For ease of reference, the remainder of these comments follows the Staff Report's numbering format and addresses associated content in each section. Sections are omitted if we have no comments.

2. Discussion, Recommendation, and Alternatives

Given the short timeframe for the development of the Phase One Tariff, we understand Staff's focus on technologies that are included in Public Service Law sections 66-j and 66-l. However, for technologies that are not included in the net metering statute, but that could benefit from the Phase One Tariff without obvious barriers to participation, why not allow them to participate? DER technologies have developed and matured significantly since that law was passed, and the benefits of new technologies will be left untapped if the Commission does not expand beyond the original scope of the NEM statute.

2.2 DER Technologies Considered

2.2.2 Energy Storage

We support the Staff recommendation to provide energy storage paired with NEM-eligible technology with access to the Phase One Tariff. Storage will provide flexibility to non-dispatchable technologies and improve their ability to take advantage of the price signals provided in the new tariff. Standalone storage is no less useful to the grid than storage paired with a generator, as it can provide the exact same services. Thus, we encourage the Commission and Staff to set a timeline for adapting the Phase One compensation methodology to include standalone storage well in advance of the timeline for completing the Phase Two Methodology. As evidenced by existing deployment of standalone energy storage in the state, there is already an economic case for using storage to support grid functions in constrained areas. The Phase One tariff can help provide the economic justification for customers to deploy standalone storage "autonomously" (i.e., without waiting for a utility procurement) and thus accelerate the deployment of storage in the state.

On the issue of environmental credits for storage, the Staff Report indicates that storage can be charged with system power, but that environmental compensation should not be provided for the export of stored system power. This is to be accomplished by compensating only for net monthly exports. However, this approach does not accomplish its intended purpose. For example, consider the case where a customer stores large amounts of solar-generated electricity, exports it at peak times, but consumes energy such that net monthly exports are zero. In this case the customer would receive no compensation for the environmental benefit they are providing. This is because it is impossible to differentiate between load and system power used to charge storage.

As an alternative, we recommend that environmental compensation be provided for the net output of the DER, rather than the customer. In the case of solar+storage hybrid systems, the net output of the combined resource is credited with environmental value. This approach not only credits solar production, but it also accounts for the losses associated with storage charging/discharging. On-site consumption does not reduce the environmental value, so it should not be a factor in the compensation mechanism.

Note that our recommendation requires the use of a separate meter, but as has been noted throughout the proceeding, behind the meter DER is likely to have separate metering for a variety of reasons, including for the tracking of attributes in the NYGATS system. Elsewhere in these comments, we make the same recommendation but for other reasons.

In developing energy storage policy generally, it is useful to recognize that the use of system power to charge storage supports clean energy it two ways: (1) if coupled with DER, it can charge using energy from the DER and discharge when it is needed the most; and (2) it can charge using energy from the grid and help address future issues with oversupply of renewables (e.g., along the lines of the "duck curve" facing the California ISO). As such, deployment of storage for use midday should be encouraged because this energy will have an increasing amount of solar content. Storage thus helps make solar dispatchable.

2.3 General Recommendations

2.3.1 Legacy Projects

To provide consistency with the Remote Net Metering grandfathering order, projects that are in service on the date of the Phase One Order should receive compensation under existing NEM rules for 25 years from their in-service date, rather than 20 as proposed by Staff. And to respect contracts with terms greater than 25 years that were made in good faith under the rules that existed at the time, the Commission should provide extensions for NEM compensation based on contract terms that were signed prior to the Commission's Phase One Order.

2.3.2 Opt-In Availability

We support the Staff proposal to allow facilities that qualify to receive NEM compensation to exercise a one-time, irrevocable opt-in to the Phase One Tariff.

2.3.4 Limited Net Revenue Impact

Please see comments under Section 3.

2.3.5 Term

We agree with the proposal that projects that come into service after the Order should retain the compensation mechanism in effect at the time of their in-service date for 20 years (unless they opt into a future rate).

2.3.7 Metering

As noted in several places below, many benefits are derived from the full output of the DER, not just the exported energy. To quantify and compensate the full benefits, the full DER output (including storage)[2] should be separately metered. As described above, this would provide:

- The ability to correctly calculate environmental benefits when storage is included (e.g., solar production minus storage losses) while eliminating environmental compensation for stored system power.

[2] Direct current, behind-the-meter microgrids are a growing resource for C&I customers. In this case where the DER is located with load behind an inverter, the output of the DER would need to be measured with a DC meter within the microgrid. DC meters should be allowed in these circumstances.

- The ability to fully value environmental benefits, including for behind the meter self-consumption.
- The ability to fully value those distribution benefits associated with avoided future capital expenditures.

The DER meter would be located at the output of the generator (or generator/storage combination). Net exports would still require the same meter at the original meter location.

2.5 Phase One Compensation Methodology – The Value Stack

2.5.2 Structural Design

A key concern with the structure of this tariff is that a value stack based only on exports will substantially undervalue several components where a portion of the benefits from a project (and potentially, the bulk of the benefits) is provided behind the meter. As we detail below, our comments focus on how generation that is produced and consumed behind the meter is treated in terms of RECs and Demand Reduction Value and Locational System Relief Value. These values are not accounted for in retail rates and should be provided when self-generation replaces retail consumption. Additionally, due to the way the Market Supply Charge (MSC) is calculated, customers that are not on Mandatory Hourly Pricing (MHP) 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.

2.5.4 Installed Capacity Value

The Staff Report states that compensation for installed capacity be based on "MW performance" during the peak hour of the previous year. This conflicts with the statement (in Section 2.5.2) that calculations should be applied to "net exported generation." This must be clarified in the order. Is compensation based on net export during the hour or on MW performance? We recommend that it should be based on net exported generation[3] for the following reasons:

- For large customers on MHP, DER production will lower the measured coincident peak usage represented in the ICAP tag, and this benefit will be captured in lower utility billing. When DER

[3] We note that our recommendation to base the installed capacity value off of exports rather than the full output of the DER is different from our recommendation for the calculation of the DRV and LSRV, where we recommend that the compensation should be based on the full output of the DER. The Phase One Tariff provides the same Installed Capacity value for exports that is already collected in the Market Supply Charge for consumption, so there is symmetry in the collection or payment of this value for imports and exports. In regard to the DRV and LSRV, these values are not collected as part of retail rates, and so these values would go uncompensated for generation consumed behind the meter if they are applied only to exports.

production during the peak hour exceeds consumption, additional compensation should be provided based on the Phase One tariff, and the Staff's proposed method of basing this compensation on the previous year's performance is a reasonable approximation of effectiveness in delivering on-peak capacity. The total benefit to the customer will therefore be the sum of the bill savings for behind-the-meter peak reduction and bill credits for on-peak exported generation.

- For CDG projects, net exported generation is essentially the same as total output, and the proposed compensation will correctly recognize the value based on the prior year's performance.

In some instances, the installed capacity value that customers provide will be inaccurately compensated for under this construct, but this is not due to compensation based on net exports but rather due to the way the installed capacity costs are collected in rates. For customers that are not large enough to receive MHP rates (i.e., those whose installed capacity costs are collected through demand rates within the Market Supply Charge), their demand rates will likely undervalue the capacity that they provide behind the meter coincident with system peak. The capacity that they provide from energy produced and consumed behind the meter will be valued through avoidance of the MSC (specifically, the MSC capacity charges that are structured as non-coincident peak demand rates) while the capacity from energy that is exported will be valued based on coincidence with system peak. Non-MHP customers that dispatch their generation coincident with system peak will likely be under compensated for the capacity they provide behind the meter relative to MHP customers. Moreover, customers that have limited duration dispatchable DER (such as storage) may be faced with the decision of either targeting the non-coincident peak demand rates in the MSC or the coincident peak capacity value for exports provided in the Phase One Tariff, but not both. Some customers may opt to receive MHP rates to better align their MSC capacity charges with the signals provided in the Phase One Tariff.

We recommend the publication of technology-specific first year values (i.e., default percentage of nameplate capacity) to facilitate financing.

Staff provided a few alternatives for non-dispatchable technologies for compensating for capacity benefits. We prefer the method that allocates the capacity payments based on performance during the top 460 summer hours rather than diving the capacity amount equally across all kilowatt-hours exported in a year. Non-dispatchable customers should be able to choose to receive compensation based on the dispatchable technology method -- using capacity provided at system peak in the previous year, so long as they are locked into that method for a period of time to prevent gaming between years where production is high or low during the peak hour.

2.5.5 Environmental Value

The Social Cost of Carbon (SCC) is used as one of two measures of environmental value. However, SCC is not calculated by the EPA on a $ per kWh basis. Rather, it is in $ per metric ton, by year in five year intervals, and by discount rate (as found in the EPA Fact Sheet[4]). Therefore, the methodology should include a method to convert the table of costs into a $ per kWh price. An example of how to do this is provided in the *Minnesota Value of Solar: Methodology*.[5] A similar methodology should be developed for use in New York.

The proposal recognizes that exported energy qualifies for a Tier 1 REC price and that it may be used to contribute toward the utility's Tier 1 obligation. In the case of CDG where all energy produced is exported, all the energy may be compensated for its environmental value (either the Tier 1 price or the SCC). The proposal also provides a second scenario for the handling of New York Generation Attribute Tracking System (NYGATS) certificates that track exported generation. It says that if those certificates are claimed for "environmental and sustainability certifications" that the certificates would not count toward the utility's Tier 1 obligation, but would be counted toward the state CES goal. It is our understanding that certificates that are claimed for the CES goal will reduce the amount of Tier 1 RECs that LSEs must purchase. So in either scenario, whether the certificate is claimed by the utility for its own obligation or the customer claims it for its own sustainability certification, the net effect is the same: the public obligation to purchase clean energy will be reduced. However, in the scenario where customer claims the certificate for its own sustainability certification, the attributes appear to be claimed twice because certificates will also count toward the CES goal (and lower the LSE obligation). We recommend that the certificates associated with customer generation should either be counted toward the customer's sustainability certification or the CES goal, but not both.

In general, although this section of the proposal was carefully worded, it remains highly unclear in many areas, for example with respect to the relationship between the overall CES goal and the Tier 1 obligation. Given the importance of this issue to both the VDER proceeding and the CES, the intent of Staff should be made completely clear so that we have adequate information to respond to and comment on what is being proposed.

There should also be a third option. Customers should have the choice to forgo receiving the environmental ("E") value as part of the LMP+D stack, and instead receive title to fully tradable RECs for their eligible generation. Customers would then be able to sell, trade, swap, or retire the RECs

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[4] See table on p. 3 of "EPA Fact Sheet: Social Cost of Carbon," https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[5] Available at: https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

consistent with their own internal policies and energy and sustainability goals. This would also further increase the liquidity of the REC market in New York State.

In the case of on-site large projects, Staff proposes that non-exported energy (energy produced and consumed behind the meter) should not be eligible to produce, for separate sale, Tier 1 RECs. This recommendation is inconsistent with the definition of Tier 1 comprising energy from eligible generators entering commercial operation on or after January 1, 2015. It is the type of generator and the installation date that determines whether the energy is Tier 1 eligible, not whether or not the electricity is consumed onsite. The Staff proposal leads to the peculiar 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. Rather, it should be the policy of New York State that all clean energy produced by DERs should be valued consistently and compensated at either Tier 1 rates or SCC rates, as the case may be.

Furthermore, Staff recommends that non-exported energy be used to reduce LSE obligations. This results in the DER providing an economic benefit to the utility without receiving compensation. It also introduces a form of double counting into the Clean Energy Standard. The Staff Report states[6] that "non-exported behind-the-meter generation will reduce LSE compliance obligations in the same manner as energy efficiency," but then goes on to state "NYGATS certificates associated with non-exported behind-the- meter generation can be recognized as contributing to the state's overall CES goal but not the CES Tier 1 obligation." In the first reference, distributed generation is subtracted from the total amount of energy consumed in the state for the purposes of calculating CES compliance (the denominator), and in the second reference, the same distributed generation is tracked and counted toward (added to) compliance with the CES goal (the numerator). This methodology will inaccurately account for clean generation produced and consumed behind the meter and will damage the integrity of the 50% by 2030 Clean Energy Standard.

The statement that the clean energy produced and consumed behind the meter will contribute to the CES goal is concerning for another reason. Many large, dynamic companies have sustainable procurement policies that require them to buy clean energy that is incremental to clean energy requirements in law and regulation, such as state RPS mandates (i.e., "regulatory surplus"). 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.

[6] Staff Report, p. 35.

Some companies will likely opt to meet their renewable energy needs through projects located in other states. For other companies that require load to be offset by projects in the same state, Staff's proposal would all but foreclose investment by these companies in New York State.

We also note that the elimination of RECs for non-exported generation is a substantial departure from policy in the previous RPS, which counted non-exported energy from the customer-sited tier toward the goal. Were the Commission to adopt this change, for some technologies, this represents a cliff and a clear departure from the principle of gradualism in this proceeding, and REV more generally. This is a change that received little, if any, focus in the stakeholder process that preceded Staff's proposal. There was also no reasoning or analysis provided by Staff on why such a sudden change is needed. A change of this magnitude should have benefited from greater discussion and consultation in the stakeholder process.

Based on the above, we recommend that the full environmental value should be compensated for all CES-eligible DER generation, regardless of ownership and regardless of whether the energy is used directly behind the meter or used by other customers (exported). The full value of environmental attributes can be recognized by separately metering the DER and applying the environmental value to the total, before netting with load.

2.5.6 Demand Reduction Value and Locational System Relief Value

The Staff Report correctly characterizes the nascent state of affairs in calculating distribution value, and it sets forth a method to estimate the value using the limited data available. However, a few value components are underrepresented, and the following remarks are intended to ensure the full values are realized.

Distribution costs can be divided into two distinct components that must be considered separately: (1) the embedded costs of past investments that are collected from ratepayers; and (2) avoided costs of future distribution infrastructure that would otherwise be required in the absence of DERs.

Behind the meter DERs have the potential to shift some of the burden of paying for embedded costs to non-participating customers by reducing demand charges.[7] This is a fair and reasonable outcome since customers are billed for their share of the distribution infrastructure based on usage. Demand charges are price signals (albeit imprecise ones) that are meant to encourage customer behavior.

The avoidance of future distribution costs is more complicated because the costs are not established, but rather estimated. For this purpose, the marginal cost of service (MCOS) studies identified

[7] This is also the case for load shifting.

by Staff represent the best available estimate for the benefit. These studies use known and existing costs as a proxy for future costs and reflect the estimated lag time before new capacity is needed.[8]

The two separate benefits—the shift of embedded costs and the avoidance of future capital investments—are represented by demand charges on the one hand and the MCOS studies on the other. The proposed Phase One tariff, however, does not recognize the full value of DER, as summarized in Table 1.

Table 1. Staff-Proposed Phase One Tariff

	CDG Projects	**On-site Projects**
Avoidance of Embedded Costs	Value is partially included when the MTC applies.	Value is captured in demand charge avoidance.
Avoidance of Future Capital Investments	Explicit value is forgone in lieu of the MTC, or if there is no MTC, the value is captured through the DRV as full production equals exports for CDG projects.	Value is captured by DRV/LSRV for exported energy, but ignored for BTM consumption.

To correctly account for the value of avoided future capital costs, the proposed Phase One tariff should be modified as follows:

- For CDG projects that do not receive the MTC, the DRV/LSRV should apply for all energy generated. This will recognize the value of avoiding future infrastructure costs.
- For on-site projects, the DRV/LSRV should apply for all energy generated, not only export energy. Note that this requires separate metering of the on-site DER.

The approach of using the full output of the DER for computing capacity value is also consistent with PJM and ISO-NE, which credit behind the meter projects for their capacity value.

The proposed tariff made use of the $ per kW-year values in the MCOS study and indicated that the resulting LSRVs would be locked in for 10 years for high-value locations. This approach would incent placement of DERs where they are needed most, and would facilitate financing. However, the MCOS

[8] See, for example, Table 1 in the the 2012 ConEdison MCOS study, "Marginal Cost of Electric Distribution Service: Final Report" available at https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/c12c0a18f55877e785257e6f005d533e/$FILE/REV_BCA_Appendix_B_(Con_Edison_Marginal_Cost_Study_2012).pdf.

studies publish year-by-year values (i.e., marginal costs for year 0, year 1, year 2, etc.), with values increasing in future years as the time of capacity additions approach. Therefore, the tariff proposal should clarify that the first 10 years of published values are locked in, not just the first year's values to be repeated each year.

The MCOS results will become a critical element of DER compensation, so these studies should be subject to the same public review as other ratemaking processes. The study inputs, assumptions, and methods should be available for review.

The proposed tariff correctly included avoided losses in the energy value, but neglected to include this in the distribution value. These should be included. Note that only losses in the distribution system (not the transmission system) should be included.

We ask that the Commission clarify that projects whose MTC is reduced to zero will receive the DRV.

2.11 Next Steps

Since tranche sizes and MTC values have not been finalized with the Staff Report, and will not likely be finalized in the Commission order, we recommend that parties be given sufficient time to review proposed values, and the calculations that went into determining the value, prior to the Phase One tariffs going into effect.

2.11.2 Utility Development of Virtual Generation Portfolios and Unbundling of Values

The virtual generation portfolios seem very similar to role envisioned for the Distributed System Providers in the REV proceeding, and requiring demonstrations where the utilities can gain experience in coordinating the operation of various DERs would help the utilities grow into their new role as DSPs. We support the Staff recommendation that utilities should develop virtual generation portfolio demonstrations.

2.11.5 Process for Development of Phase Two Tariffs

We plan to address this topic in full in our response to the notice requesting comment on the Phase Two process. However, in general, we support continued engagement of stakeholders, but with a more formal process that should include outside facilitation, as well as hiring of consultants to provide timely quantitative analysis that can support deliberations and decision-making.

Since different technologies will be provided different compensation even when they are delivering the same value to the grid, we suggest that the Commission take the following near-term steps to level the playing field ahead of Phase Two:

- Once locational areas have been identified in the development of the Locational System Relief Values, the existing utility Dynamic Load Management Programs should be modified to allow demand response resources to participate in providing those Locational System Relief Values as well and have the option to receive a fixed price for capacity over 10 years. Certain constrained zones, such as the higher price "Tier 2" zones in Con Edison's programs, could be considered for a fixed price starting in 2017.

- In time for the 2017 dynamic load management programs, utilities should add the environmental value that is available to NEM technologies to payments for the dynamic load management program. If the Commission is reluctant to provide the full value to customers that load shift or use storage, an approximate amount could be added based on the emissions benefits of load shifting. Customers who attest to not load shifting should receive the full value immediately.

3 Evaluation of Phase One Impacts and Design

The advanced energy community recognizes the need to manage any revenue shift associated with both NEM and the proposed Phase One methodology, and is therefore generally supportive of the proposed approach outlined in this section, notwithstanding concerns that we have noted elsewhere in these comments with regards to other elements of the proposal. The desire to cap revenue impacts at 2% seems a little conservative. Even so, according to Figure 4, the 2% cap is not a constraint on either National Grid or Consolidated Edison, and only a modest constraint on NYSEG and RGE. Therefore, for these utilities, the choice of 2% should not have a material effect on the Phase One program. It only appears to be an issue for Central Hudson and O&R, in that it could constrain development during the Phase One period. However, in light of the revisions to the tranche estimates made after correcting for errors in the original calculations, we recommend raising the revenue shift impacts to 3%.

Beyond these specific comments we remain generally concerned that the Staff Report contains only illustrative examples based on the analytical framework that was developed. With much of the onus placed on the utilities to develop the actual stack values and tranche sizes, we do not anticipate having the opportunity to comment on these values prior to the Commission issuing its order in early 2017. As such we recommend that the order contain a well-defined process and timeline for making these details available to stakeholders so that they can review them and the underlying assumptions and calculations, and provide comments prior to the Phase One rates going into effect.

4 Design of Tranches and Analysis Results

As with the approach to the revenue shift outlined in Section 3, the advanced energy community is generally supportive of the approach for determining tranche sizes, including the proposed allocation of the opportunity to the different tranches. Nevertheless, the Commission should be prepared to adjust the tranche sizes if the market is not responding. In particular, NYSEG & RGE have significant flexibility in tranche sizing, due to the large size of Tranche 3 (based on the resided spreadsheets).

Because Central Hudson & O&R are the most constrained by the Phase One proposal, interconnection queue management and SIR rules become vitally important to enabling the market in the near term, and raises the risk that developers may challenge the outcome of project prioritization within the queue. As such, we strongly urge the Commission to establish a transparent process for managing complaints.

In Figure 6, some of the column labels appear incorrect, although based on other similar charts, we think we know what we are looking at.

Conclusion

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New York State. In broad terms, the advanced energy community supports the overall direction of Value of DER proceeding, but we have also included in these comments some significant sources of disagreement. We recognize the complexity of what is being undertaken and look forward to our continued involvement in this proceeding and working with all parties to develop a suitable framework for accurately valuing and compensating distributed energy resources in a manner consistent with the intentions of REV.