December 19, 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 reply 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

Reply 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. competitiveness 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.

1 - Introduction

AEEI, ACE NY, and NECEC appreciate the opportunity to respond to the comments of other parties on the Staff Report ("Report" or "Proposal") in the Value of DER Proceeding. We continue to support the Commission's vision of increasing the accuracy of price signals for DER and aligning compensation with system needs. Below we respond first to the comments of the Joint Utilities (JU), given their extensive comments and analysis. We then comment more generally, by topic, on the comments of the other parties.

2 - Response to Join Utility Comments

We appreciate the details provided by the JU in their Initial Comments, and for their inclusion of some of their work papers in the record. As a general matter, given the extensive, quantitative nature of the analysis provided by the JU, and the short timeframe allotted to parties to provide Reply Comments, we note that we have not had sufficient time to fully assess the JU's calculations. Given that the results of the JU calculations diverge significantly from those of the DPS Staff, we strongly urge the Commission to review the JU calculations carefully, and to inform parties on the source of the discrepancies. For example, below we have attempted to identify some sources of difference between Staff's calculation of revenue shift and those of the JU, but we have not been able to fully compare the two sets of calculations.

Use of Distribution Peak instead of System Peak to Calculate Distribution Costs

The JU note that Staff's Proposal uses wholesale system peak coincidence, instead of distribution system peak coincidence, and that Staff intend to update estimates using local peak demand. The use of local peak demand, to the extent that a utility can reliably measure it, is the correct approach, and this should be performed in estimates of revenue impacts. Information on distribution peaks would also have to be made readily and easily accessible to DER providers and operators, otherwise, they would not know when a distribution peak might occur and they would not be able to respond appropriately.

The Joint Utilities further indicate that in an example of a distribution peak on ConEd's system, this change would lower the distribution value from 2 cents to below 0.1 cents per kWh. However, no data is provided for this result. The JU does provide numerical results by utility. For Central Hudson, the JU estimates a 22% capacity factor over the top 10 hours[1] instead of 53% as calculated by Staff. While Staff showed the hourly NYCA loads and corresponding solar output for each hour, the JU did not provide a comparable calculation. Therefore, it is not clear where the 22% came from nor what load data

[1] JU workpapers, tab CH(2), cells G22 and G23.

was used to derive it. It is possible that the selected feeder used in the calculation was not representative, but in any event, it is not possible for us to evaluate this.

ICAP Value Based on Modeled Results

The JU suggests that that compensation for DER should be based on modeled output of solar during the last five years. There are three problems with this approach. First, solar production profiles do not represent other eligible DER technologies: wind, micro-hydro, farm waste, fuel cells (< 2 MW), micro-CHP (<10 kW), and energy storage if paired with an eligible DG technology. Consequently, the proposed change would not be a suitable method for determining compensation for these technologies.

Second, the JU method would hinge upon modeled output for a single sample year, while the Staff recommendation is based on actual, metered data during the prior year's peak. It is generally more accurate to measure energy output than to model output, so the Staff method is superior. The use of interval meters as proposed by Staff not only overcomes modeling error, but also provides a means for determining output of non-solar resources, and this is not possible with the JU proposal.

Finally, the proposed modeling suffers from an analytical problem because it relies on solar irradiance data ("typical meteorological year") collected from the wrong days. The problem is described in the AEE-ACENY-NECEC filed review of the Benefit Cost Handbooks.[2] In that filing, an example is provided showing that solar irradiance data used to model one location on the peak NYISO load day of 2015 was collected in 1977, and that the use of such non-synchronized datasets led to significant errors. The JU method goes further to propose using the same dataset (e.g., 1977) to compare outputs in each of five years (2011-2015), introducing errors in each of five years.

We therefore support the Staff proposal to used technology-agnostic metered data rather than solar-only modeling results.

Use of EIA Data

We agree with the JU that the EIA data should not be used in the calculation of tranche sizes, and their approach of using a three-year average is appropriate.

Analysis of Bill Impacts

The JU made a logical error by claiming a 25% increase in annual NYSEG residential bills[3] while at the same time arguing that the corresponding result of 8,000 MW of new DER capacity is technically infeasible on a system with a peak annual demand of only 3,190 MW. If the 8,000 MW of DER capacity is not technically feasible, then the 25% increase could not happen.

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[2] Corrected version, filed August 30, 2016, Case 16-M-0412 and Case 14-M-0101, pages 12-13.
[3] JU Filing, p. 16, Table 2, NYSEG.

The problem is that the JU did not properly interpret the results of their analysis, notably their calculation of 7,202 MW for Tranche 3. The 7,202 MW is the numeric result that indicates how much DER capacity would correspond to a 2% net increase in revenue, not a forecast of actual participation. Since this result is technically infeasible, the JU should have concluded that the 2% limit would not be reached.

The claimed 25% bill increase is also based on a confusing set of mixed assumptions: that the MTC would be calculated using Staff's methods for value of distribution and ICAP, but the determination of bill impacts uses the alternative JU methods. However, if the value of distribution/ICAP methods proposed by the JU were used to calculate both the MTC and the bill impacts, then the bill increase would correspond to the 2% limit.

Simply put, the issue should be framed differently. The question is "which methods for calculating the value of distribution and ICAP should be adopted?" The method proposed by Staff? The method proposed by the JU? Some other method? Regardless of selection, the calculation of tranche sizes should be done with a uniform methodology based on whatever upper limit on costs the Commission ultimately adopts. (AEEI, ACE NY, and NECEC recommended 3%, whereas, our comments on value of distribution and ICAP methods are provided in the sections above).

It is worth noting that both Staff and the JU calculated the revenue impacts assuming that all DERs would be solar, producing output for this technology only. Solar plus storage may have significantly better capacity factors in the top 10 load hours, so the MTC and revenue impacts would be correspondingly lower.

Line Loss Adjustment

We agree with the JU that line loss avoidance is project-specific and is worthy of future study. The JU indicated that loss adjustment would depend, for example, on interconnection voltage. It would also depend upon hourly load so that DER producing power on peak would be able to avoid more losses than DER that produces power at other times.

For this reason, using average line loss figure is likely to undervalue the impact of solar and storage in improving line losses. Solar tends to produce during the day when load on the system is greater than average, and storage can both discharge during high load when losses are there highest and charge at night when losses are lowest. Given that losses generally follow the I^2R model (where losses increase exponentially with current), this delta between losses for storage's charging and discharging cycles can be quite large. For these reasons, the staff methodology is more likely to underestimate loss avoidance than over estimate it.

MCOS Granularity

We agree also 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. To simplify matters, a future alternative would be to calculate MCOS in each defined region, whether high value or low value, and calculate its corresponding distribution value. This would avoid some of the complication involved with adjusting the underlying averaged MCOS value as specific costs are removed from the MCOS and added on top as a separate LSRV. Instead of having stacked MCOS and LSRV values, there could be a signal value in a planning area that is granular enough to capture specific capacity needs.

The MCOS studies, being critical to the quantification of distribution value, should be open to public review of data and methods.

Community Solar Profit Margins

We strongly disagree with the JU calculation that shows community solar projects achieving an 80% profit margin,. The implication by the JU is that Staff's proposal would result in a windfall for developers. There are, in our assessment, two main reasons why the JU calculation is incorrect. First, in their calculation of profit margin, 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.[4] Changing this one assumption[5] from 2% to a more realistic 8% leads to a profit margin of just 12.8%. Second, we find that the JU estimate of a total installed costs of $1.85/Wdc is unrealistically low for a community solar project in an undeveloped market such as New York. For example, the proforma analysis included some costs (land, permitting, and interconnection) based on a 100 MW plant, whereas the assumed plant is only 2 MW, located near the loads on a distribution feeder. These costs for the smaller plant would be much higher on a per-kW basis.

Also, the analysis ignored many of the expenses that the CDG would incur, including customer acquisition costs and ongoing administrative costs. The analysis also falsely assumes that a project owner would receive the full credit value as revenue. It is the customer that receives the credits. CDG projects receive their revenue from customer payments, which need to be lower than the value of the credits in order for the customer to realize any financial benefit. The analysis is therefore highly misleading and is not representative of a CDG project.

[4] Note that the yield on a 10-year U.S. Treasury is 2.55% on December 19, 2016.
[5] Cell B19.

3 - Response to Other Commenters

3.1 General Structural Comments

NYBEST, the National Fuel Cell Research Council, and Bloom Energy all agreed 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. As we stated in our Initial Comments, the Phase One Tariff does not provide price signals or compensation for values delivered by purely behind-the-meter, self-consumed generation, despite the fact that self-consumed generation from DER has demonstrable benefits that are not valued in existing retail rates. In fact, the retail rate serves to undermine the business case of many dispatchable DERs that have value to the system. This will leave the significant potential of non-exporting resources untapped until this is addressed in rates or the Phase One tariff.

On the application of the Phase One tariff to stand alone storage, NYBEST stated that two portions of the value stack, system capacity values and local delivery values, could be applied to non-exporting storage that modifies load behind the meter. Metering the storage at its output would allow for accurate accounting for its contribution to load reductions and to bulk and distribution system capacity. We agree with NYBEST that the DRV and LSRV could easily be applied to non-exporting storage, as well as to other technologies that were not included in the Phase One Tariff. The system capacity value (Installed Capacity) is more complicated as this value would already be recognized for those customers currently being charged under mandatory hourly pricing (MHP). For those customers that pay for system capacity through non-coincident peak demand rates as part of the Market Supply Charge, storage that is dispatched during system peaks would be undervalued by the current rate structure, and we agree that these customers should be appropriately compensated for what they provide.

The above discussion highlights the difficult interplay between a more accurate compensation mechanism for exports and a less accurate valuation as provided through existing retail rates. SolarCity came up with a partial solution to this problem for storage by proposing that it be allowed to charge using the Mandatory Hourly Pricing tariff, providing a way for storage to participate in economically beneficial arbitrage. Assuming that DER is metered directly, this approach is feasible and we support its adoption.

SolarCity and others also proposed that excess credits under Phase One be paid out on an annual basis, consistent with laws governing net energy metering, rather than carried over indefinitely, as proposed by Staff. Those laws[6] stipulate that excess NEM credits would be paid out at the utility's avoided cost after a year. We support this proposal as well.

3.2 Environmental Compensation

One of the deepest areas of concern for the advanced energy community in the Staff proposal was the proposed treatment of environmental attributes. Many parties had concerns with this portion of the Staff proposal, including NYPA, CORE, Bloom Energy, SolarCity, NFCRC, NY-BEST, and Pace.

We are in strong agreement with Pace's assessment of the problems that would result from Staff's proposed method of providing compensation for environmental attributes. We also agree with Pace's proposed solutions 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 in New York State.

Other parties agreed with our concerns in part. NYPA stated that exported energy should create Tier 1 RECs, and that the customer should retain the rights to fully tradeable RECs if they forgo environmental compensation in the Phase One Tariff. Our position is similar, except that all generation from an eligible generator, regardless of whether it is consumed onsite or exported, should generate RECs (eligible for sale into Tier 1 or elsewhere) if the customer forgoes environmental compensation.

Several parties took issue with the lack of any sort of compensation for environmental attributes for generation consumed on-site, including CORE, Bloom Energy, SolarCity, and Pace. SolarCity notes that many DERs will not receive NYSERDA incentives in the future, leaving energy consumed on-site without any type form of compensation for the emissions it reduces. Bloom Energy noted that this is a significant change from prior policy, which allowed on-site generators to sell RECs into the main tier of the RPS, including for energy that was not exported. They also note the lack of discussion or deliberation in the stakeholder process on this issue. We share Bloom Energy's concern about this shift in policy. It would harm the potential of on-site DERs that are installed to meet local load. The benefits of such a policy shift are not at all clear to us.

We oppose the City of New York's recommendation that customers should retain ownership of their RECs while those same RECs are counted against the utility's Tier 1 obligation. We do understand the desire of the City to clarify that claiming a NYGATS certificate as progress toward the CES goal is ultimately the same as a utility counting the REC toward its Tier 1 obligation. We too were puzzled by the distinction created in the Staff proposal between the Tier 1 obligation and the overall CES goal. However, we believe the City's recommendation is misguided as it would count a certificate twice. If a

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[6] Public Service Law § 66-j 4(C).

company claims a certificate for its own sustainability requirements, the customers of a utility (through the utility's purchase of the REC for the Tier 1 obligation) cannot claim that same REC toward their energy usage. The point of a REC is to track and count renewable attributes. If a REC can be claimed more than once, the REC mechanism is no longer fulfilling its core purpose of accurately tracking renewable attributes.

On a related matter, Multiple Intervenors (MI) has repeatedly stated its opposition to any form of payment to DERs above current estimates of value they provide. MI States that the value should be accurate and the pace of development should be left to the market. While we notionally agree with the concept, we also recognize that it is not possible at this time to accurately value pollution reductions given the long timescales involved and the variability in damage projections. An accurate price signal for carbon also assumes that the industry will adjust to lower carbon emissions in an economically efficient manner. However, technological, legal, and other barriers remain that would prevent even an accurate valuation of carbon from delivering the desired emissions reductions in current circumstances. In the meantime, progress must be made toward New York's carbon reduction goals, which an overwhelming majority of New Yorkers support[7]. We urge the Commission to consider the benefits of ongoing market development as it balances current costs to customers and long-term achievement of the state's goals, so that DER can continue to evolve technologically and decrease the long-term cost of meeting clean energy and carbon reduction targets.

3.3 Distribution Capacity

MI states that the Locational System Relief Value should vary annually like the Demand Reduction Value, instead of fixing the value over a 10-year period. Such an approach would fail to recognize a key distinction between these two distribution system values. The DRV is an estimate of incremental capacity costs across the system and it is not tied to any specific investment in the system. This estimate will correctly vary over time based on system conditions and as the costs of new capacity additions are used to update the projections. However, the LSRV is tied to a specific upgrade on the system that can be deferred or avoided through DER. This is why the LSRV is structured with a limited amount of available capacity and a higher dollar amount, as both are tied to a specific need. Any utility upgrade would be a long-term investment, so it follows that any replacement capacity from DER would need to persist for an equivalent duration. Payments that vary annually would undermine the financeability of DER that is deployed to meet locational system needs. Further, any possible decreases

[7] 72% of New Yorkers support increasing clean energy, even if it results in a small increase in utility bills. http://www.nature.org/ourinitiatives/regions/northamerica/unitedstates/newyork/climate-energy/new-york-voter-attitudes-on-clean-energy.pdf

in LSRV payments from future DER deployments (because the same LSRV dollars would be divided across more kWs) would increase financing risk. The Staff method appropriately keeps the participating kWs and payment values static to reflect the targeted avoidance of specific costs over long durations.

3.4 MTC and Tranche Structure

We agree with Pace that for any project that receives a Market Transition Credit for any portion of its generation, the DRV should apply to the portion of the generation that does not receive the MTC. Applying both values to a project could be a way to provide performance-based compensation while providing a stable revenue stream that will encourage financing.

Given the contested nature of the tranche sizes and the questionable analysis provided in the JU comments, we agree with the Coalition for Community Solar Access (CCSA) 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. We believe this would help improve the confidence of many of the parties involved in the final outcome. We also agree with CCSA that there should be a public reservation system that is transparent so that companies can anticipate where their projects are likely to fall within the tranches.

The advanced energy community agrees with CORE that utilities should receive only the data necessary to calculate the credits and apply them to the customer bill, but should not get data that might weaken the competitive position of the DER providers. This is an increasing area of concern due to the recent petition by Consolidated Edison asking for permission to own and receive a regulated rate of return on community solar serving low-income customers.[8] This raises the possibility of DER providers working in direct competition with the utility in the event that a utility is allowed to provide DER to customers.

3.5 Market Signals from Phase One Tariff and Unintended Consequences

CORE raises the possibility of market distortions and unintended consequences that may occur if the Staff proposal is enacted without modification. CORE states that many companies that might have normally pursued on-site development will instead turn to CDG projects in order to capture the MTC value. Further, many on-site projects may switch to a CDG model if that allows them to access environmental, demand reduction and system relief values that would not be available to onsite projects for energy produced and consumed on-site. This may have the unintended consequence of further increasing the prevalence of CDG projects in New York interconnection queues and leaving otherwise viable on-site DER opportunities undeveloped. This is despite the fact that locating DER on-site with load

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[8] Petition of Consolidated Edison Company of New York, Inc. for Approval of a Pilot Program for Providing Shared Solar to Low-Income Customers in case 16-E-0622

has additional benefits, such as increased reliability for the customer and decreased losses on the distribution system.

3.6 Other issues

MI disagreed with the proposal to offer customers with net-metering the option to opt in to the Phase One tariff. They described it as a "lose-lose" scenario from the perspective of non-participating customers under the premise that a project using NEM would opt-in only if the project found it more lucrative, thereby compounding incentives borne by customers. On the contrary, 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. Further, the LSRV might incentivize an existing solar project to increase its capabilities with storage in order to fully capture the value. In this case, the project would be paid for capacity delivered. It is unlikely that, absent a high LSRV value, a project would find any value from switching from retail rate NEM to the Phase One tariff.

We agree with the Advanced Energy Management Alliance (AEMA) that payments for dynamic load management programs should reflect the environmental benefits that demand response provides, and we recommend that the Commission modify those programs do include environmental values. We also agree with AEMA that some dynamic load management customers should be able to "lock-in" their program pricing for 10 years, but we believe it should apply more narrowly and not to all aspects of the dynamic load management programs. Consistent with the rationale behind locking in the LSRV for 10 years and not the DRV, those Con Edison programs that target locational constraints and defer the costs of specific upgrades should allow customers to lock in their program rate for 10 years. Con Edison's Tier 2 zones may be a good place to start.

4 - Conclusion

AEEI, ACE NY, and NECEC appreciate the opportunity to comment on the Staff proposal and respond to the input of other parties. We reaffirm our support for the goals of the Value of DER proceeding, and we look forward to supporting the effort as it moves into Phase Two.