February 25, 2019

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:

Advanced Energy Economy Institute (AEE Institute), 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 a single set of comments on the following white papers filed by Staff: Whitepaper Regarding Capacity Value Compensation; Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates; and Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs.

Respectfully Submitted,

[Signature]

Ryan Katofsky
Managing Director
Comments on Staff Rate Design White Papers  
(Case 15-E-0751)

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

Preface

In order to respond to the three white papers\(^1\) filed in this proceeding by Staff on December 12, 2018 (“Staff White Papers” or “Staff Proposals”), Advanced Energy Economy Institute (AEE Institute) is working with Advanced Energy Economy (AEE) and two of its state/regional partners, the Alliance for Clean Energy New York (ACE NY) and the Northeast Clean Energy Council (NECEC),\(^2\) and their joint and respective member companies to craft the comments below. These organizations and companies are referred to collectively in these comments as the “advanced energy community,” “advanced energy companies,” “we,” or “our.”

The advanced energy companies have responded to specific elements on each of the three Staff White Papers within a single set of comments. While we generally find the proposed changes to be favorable improvements, silence on any particular proposal does not imply support or opposition.

Capacity White Paper

We support Staff’s proposal to reduce the number of hours eligible for capacity compensation in capacity Option 2 although we have concerns about moving the time window earlier in the day. The Staff Proposal recommends moving the hours up by one hour to 1-6 pm from 2-7 pm, citing the historical New

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2 AEE is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products, and services that enhance 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
York Control Area (NYCA) peak system hours. As seen below, the NYISO system peak hour has not fallen between 1 PM-2PM since 2006, and since that year, has fallen after 3 pm every year.

While no ICAP hours have fallen from 7-8 pm, the data is clearly trending toward a later peak than an earlier peak. We believe recent trends are a better predictor for future peaks. Further, current peak demands do not factor in the growing contribution of solar and other non-dispatchable renewables. The emergence of the “Duck Curve” in California has shown the importance of considering net demand (demand net of solar and non-dispatchable renewables) in system planning. As solar penetration increases, shifting some of the solar production to later hours through storage or tracking systems will become increasingly valuable and will slow the development of a Duck Curve in New York. A recent presentation from Astrape consulting to the NYISO demonstrates this trend as renewable penetration increases.³

³ Astrape Consulting. Presentation to the NYISO MIWG/ICAP/PRLWG. February 15, 2019
Considering the project development timeline in New York, the Commission should have 2025 in mind as they determine appropriate windows. Moving the hours up from 2-7 pm to 1-6 pm will increase the likelihood that ratepayers will pay for capacity twice, once through VDER for capacity provided from 1-2 pm and again to the NYISO if the NYCA peak is during the 7-8 pm hour. It is also likely to decrease the business case to install storage and tracking systems, which would maximize evening solar production coincident with future system capacity needs.

Those systems that do not have tracking or storage systems can choose capacity Option 1, which provides capacity compensation for each kWh, regardless of when it is produced. Option 2 should support the business case to install storage and tracking systems so that solar systems built today are better positioned to meet expected system capacity needs and mitigate the negative impacts of a “duck curve.” We therefore recommend that standalone solar project owners have the option of a 2-7 pm window and that hybrid solar + storage projects have the option of a 3-7 pm window. Considering the trends highlighted above, a 3-7 pm window is likely to capture the peak hour, without unnecessarily de-rating the value of four-hour energy storage systems. A five-hour window is damaging to the business case for storage, without providing a clear benefit to ratepayers, and complicates progress toward meeting the state’s energy storage goals.
Avoided Distribution Compensation White Paper

DRV Time Period

It appears that the Staff Proposal adjusted the DRV eligible hours to coincide with capacity Option 2. Unless there is a clear reason for having different DRV hours, we recommend that the Commission adopt the same hours for DRV that AEE has recommended for ICAP Option 2. Solar only resources would have a DRV window of 2-7 pm and hybrid solar + storage resources would have a DRV window of 3-7 pm. While we are mindful of too many options and avoiding complications, having slightly different windows is prudent for future system planning. Indeed, as demonstrated in the Astrape slide, a MW of storage output from 6-7 pm will be far more valuable to the future system than a MW from 2-3 pm, when solar is near its peak output. The windows should align with this reality. Having consistency between installed capacity and the DRV will simplify operations for projects and improve overall compensation.

CSRP Compensation

We support Staff’s proposal to allow projects that prefer a smaller number of hours with a call signal to opt out of receiving the DRV and instead participate in the utility Commercial System Relief Program (CSRP). Staff appropriately recognizes that not every project will want to operate for the entire 245 hour period in the summer, and that a project’s availability during the highest of the peak load hours, as represented by the CSRP dispatch trigger, can provide high system value.

With that said, some features of current CSRPs are likely to pose barriers to some types of DER that are currently eligible to participate in VDER. We therefore support Staff’s recommendation to direct utilities to modify the rules of their CSRPs to permit resources to perform by injecting electricity into the distribution system. We recommend that the Commission direct utilities to also modify the rules of their Distribution Load Relief Programs (“DLRP”) to permit resources to perform by injecting electricity into the distribution system. Allowing injections during DLRP events, which are triggered by local contingencies, could strengthen reliability.

We also have concerns about the ability of baseload DERs to participate in CSRPs. The current DRV construct compensates for injections during the 10 highest load hours, even if those injections are persistent for all of the other hours of the day and year. In CSRP rules, persistent load reductions (and now potentially injections) are included the baseline performance of a customer and are not compensated for.\(^4\)

\(^4\) By way of example, assume that a customer with 200 kW of load also has 300 kW of BTM battery storage and typically between 2PM-6PM exports 100 kW to the grid. Under a traditional baseline methodology, the customer’s baseline between 2 PM-6PM would be -100 kW. Since CSRP performance is based on the difference between the
Switching from the current DRV construct to the CSRP would result in a loss of compensation for these types of generators, such as fuel cells. The generation profile of these baseload DERs should be delineated from the load profile of customers so that appropriate compensation is provided. The same is true for energy storage resources; performance for the storage should be measured at the battery level and be evaluated exclusively on the performance of the battery during the DRV or capacity interval on that specific day.

We contend that one such necessary change is modifying the CSRP value to equal the proposed DRV value, unless there is adequate rationale for why the CSRP and DRV values should be different. If a project is available and performs during the CSRP dispatch trigger, which for most utilities is 92% of the system peak or network peak, it would seem to avoid similar costs as represented by DRV, especially considering Staff’s clarification that “the $/kW-year used to calculate the starting DRV will be based on the MCOS studies used to calculate the original 10-hour DRV.”

Our understanding is that CSRP values are also based on the Marginal Cost of Service (MCOS) studies. We recognize that a resource that performs during the top 245 peak hours of the year may have more value than a resource that performs for fewer hours. However, even under Con Edison’s current VDER tariff, the compensation is $199.40/kW-yr for a resource available for the top 10 peak hours. CSRP compensation is currently $90,000/MW-yr ($90/kW-yr), even though the program is dispatched at 92% of utility or network peak. For many utility territories, this means that CSRP is dispatched in excess of ten hours a year. Therefore, we contend that the CSRP value should equal at least this $199.40/kW-yr (or the DRV value in other territories), unless utilities can provide adequate rationale for the CSRP being lower.

Finally, it is critical that projects that participate through VDER have the option of receiving the DRV value through payments instead of bill credits, recognizing that customers with higher bills will still prefer bill credits. For standalone projects that do not have associated accounts for which the bill credits could be transferred, or that have accounts with minimal charges, not receiving payment serves as a major impediment to developing a project and accomplishing state storage goals. Developers for such projects need to find third party off takers who can utilize the bill credits, adding a complicated layer to developing a project. Since the DRV benefits to ratepayers are the same regardless of whether it is a bill credit or payment, it is in the best interests of ratepayers to allow the option for payments. This will also help the state meet its storage goals. That said, we recognize that the Commission is mindful of jurisdictional issues, baseline and the customer’s load at the time of an event, the customer would not receive credit for energy storage as part of CSRP, despite the battery discharging 300 kW. If the battery were in front of the meter, it would get 300 kW of credit, and since the impact on the grid is the same if the battery is BTM, it should also get 300 kW of credit—200 kW through offsetting demand and 100 kW through compensation via the CSRP and VDER. Therefore, it is important to meter the battery for output, and base performance and compensation off output during that interval.

and therefore are only proposing a payment for the distribution-related DRV value, and not wholesale values.

**Standby and Buyback Rate White Paper**

**Voluntary Standby Rates for Mass Market Customers**

We support Staff’s White Paper to provide opt-in standby distribution rates for all mass market customers, regardless of whether the customer has on-site DER. We also enthusiastically support Staff’s suggestion that these opt-in standby distribution rates be coupled with improved supply charges based on hourly NYISO Location-Based Marginal Prices (LBMPs) and capacity charges based on customer-specific ICAP Tags. We note that Staff’s proposal on the design of a market-based mass market supply rate is very similar to Commonwealth Edison’s Basic Energy Service Hourly tariff. A recent review of this rate by one of Illinois’ consumer advocates, the Citizen’s Utility Board, shows that 97% of residential customers in Commonwealth Edison’s territory would have saved money if they had switched to the hourly pricing rate even without making any behavioral changes. We are encouraged that Staff are considering the idea of a dynamic mass-market market-based supply rate and are taking it a step further with a standby distribution rate.

We understand and agree with arguments that these types of dynamic rates are not for everyone, but rate design, particularly with opt-in rates, should not be a lowest common denominator exercise. Customers who are willing to take on performance risk in exchange for the potential to lower their bills should be allowed to do so. Customers who participate stand to benefit individually, and they are also likely to provide system-wide benefits by lowering investment needs in both the distribution and wholesale systems through changing their usage. This in turn will lower revenue requirements assessed to non-participating customers. It is for this reason that cost increases to non-participating customers are not an inevitability, even while participating customers realize cost savings. Smart rate designs that encourage more efficient behavior should not be seen as a zero-sum game that merely shift costs through the elimination of cross subsidies inherent in “averaged rates.” They have the potential to create new benefits that are not possible without better price signals.

Staff raised the concern that non-participant rates might increase due to the reduction of cross subsidies as customers with a lower cost of service opt-out of “averaged rates.” While Staff are correct that rate increases for non-participates are technically possible, the level of adoption that would be required to

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achieve such a shift exceed what most other utilities have achieved in practice with dynamic opt-in rates. Further, any increase in cost for non-participating customers would not be unjust or unfair if their actual cost of service is higher.

That said, the Commission rightly should be concerned about cost impacts on customers, especially those that are in financial need. The Commission has different means at its disposal for moderating those impacts. It is not reasonable to assume that a customer who remains a non-participant and whose costs increase is also in greater financial need than a customer who opts-in to the rate and responds to the new price signals. Customers may opt-in because they are under financial pressure and the rate provides them with a new way to save money that was not previously available. The objective of the rate—to incent more economically efficient consumption—is separate from other Commission programs that are designed to provide financial relief to those in need. Limiting the rate increase for non-participant customers would limit the benefit of the new rate (through limiting participation) and would skew the price signals sent to both participating and non-participant customers. It would also provide rate relief to customers in an untargeted way regardless of customer need. Instead, we recommend that the Commission use programs that target customers in need to provide relief in a systematic way and avoid impeding the ability of new rate designs to incent efficient customer behavior.

**Allocated Embedded Cost of Service Study**

We strongly support Staff’s recommendations for more accurate accounting between local and shared costs, which would then impact the allocation of contract demand and daily as-used demand charges respectively. We are concerned that absent reform and more accurate allocation, contract demand will inhibit the growth of energy storage projects in New York and create an artificial cost for power injections that provide capacity and provide valuable support to the grid.

Per Staff’s comments in the Standby White-paper, “The Contract Demand Charge would be designed to recover the costs of “local” facilities, that is, facilities that are closer to a customer’s site and were put in place mostly to serve the individual customer.” This aligns with The Regulatory Assistance Project’s recommendation in their Smart Non-Residential Rate Design paper, where they stated:

Non-Residential (NR) Principle 1: The service drop, metering, and billing costs should be recovered in a customer fixed charge, but the cost of the proximate transformer most directly affected by the non-coincident usage of the customer, along with any dedicated

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facilities installed specifically to accommodate the customer, should be recovered in a NCP demand charge.

Data points from other jurisdictions suggest that “local” costs (customer-specific capacity costs) in New York are substantially higher than in other jurisdictions, even when adjusting for the more expensive nature of building infrastructure in New York City and the surrounding area. In Washington State, an AEE member recently developed a 3 MW interconnection for their test laboratory with the local IOU-Avista. The cost for two 1500 MVA pad-mount transformers along with the conductors needed to connect to the facility was $60,000. This results in a $20/kW capital cost. If you spread that cost over a twenty-year life, that equals $1/kW-year for the dedicated equipment need to support this DER system. Con Edison’s monthly Contract Demand charge ranges between $84 to $96/kW-year. While one needs to account for costs in New York City, and an urban design using vaulted equipment and an N-2 planning criteria, annual costs for Contract Demand seems distorted. The cost structure that supports this level of Contract Demand should be reviewed to ensure that the cost allocated should be “to recover the costs of ‘local’ facilities.”

We are encouraged by the study performed in National Grid’s territory and the resulting change in the allocation of local versus shared costs.

The categorization of local versus shared costs is a very important issue for the evolution of rate design in New York. The utilities should be required to demonstrate that a cost categorized as a local cost would not be incurred if not for that specific customer/project’s demand or injections. They should also demonstrate that the local cost is an ongoing incurred cost driven by that customer/project’s demand or injections, and not a one-time cost that should be covered in interconnection fees. The supporting data should also demonstrate whether the local cost is impacted in the same manner by export as it as by customer/project demand; for instance, on page 17 “Con Edison noted that it is unlikely for a customer’s export to place additional demand on substation facilities. It therefore proposed to eliminate the portion of substation costs included in the Contract Demand Charge for Buyback Service customers taking service at the primary voltage level.”

Given the range of interpretations that could be applied to whether a cost is local (customer-specific demand) or a shared cost (caused by the aggregate demand of multiple customers), we propose that the Commission adopt a clear test to delineate between the two types of costs. Specifically, a cost should only be classified as a local cost if 1) an increase in demand or a power injection from a single customer/project could contribute equally to an increase in costs and 2) only one customer/project drives the cost, such that the cost cannot be avoided or diminished by the injections of another customer/project. This test clearly defines local and shared costs by defining each by the impact of a power injection into the system. A true customer-specific, local cost is driven by the peak flow of power, regardless of the direction. A connection must be large enough to handle power flows in any direction to and from the customer. Customer-specific
demand also results in upstream demand requirements that are shared with other customers. In contrast, power injections from a customer usually reduce the need for upstream capacity to meet aggregate customer demand, especially when these injections are provided during periods of high demand. An injection could only result in reduced need for capacity if the infrastructure is serving the capacity needs of other customers. So long as a category of cost has the potential to be reduced by an injection, it should be classified as shared. If shared capacity costs are defined as local costs, then it is possible that a storage system would be overcharged for local costs (via contract demand) when it is in fact providing a benefit—such as reducing stress on feeders and transformers that are used by multiple customers. Our proposed test would accurately recover the local costs of the power injection, while avoiding penalties for providing grid support that run counter to New York State goals for DER and storage deployment.

We note that Staff proposes that the “Allocated Embedded Cost of Service Study” be done in each utility’s next rate case. Nowhere is this issue more important, or more limiting to the development of new projects, than Con Edison’s territory. We recognize that Con Edison recently initiated a rate case, and we respectfully urge the Commission to direct Con Edison to perform this study and make any necessary adjustments to standby and buyback in the rate case.

**Granular As-Used Demand Charges**

We strongly support Staff’s recommendation that the Commission direct Central Hudson, Niagara Mohawk, NYSEG, RG&E, and O&R to develop more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components during the summer period for their existing standby rates and submit such rates for Commission review and approval.

This recommendation aligns closely with the core objective of REV for greater system efficiency. Having a flat demand charge based on usage over a 10-12 hour period greatly limits the ability to improve load factor and reduce peak demand. Super-peak charge components, as developed in Con Edison’s territory, sends a signal to customers to invest in technologies that reduce their demand during higher usage, higher cost hours.

Each utility should have a super-peak charge, unless they can demonstrate that their network or system costs are flat throughout the day, and that higher demand during peak hours imposes no additional costs or wear and tear on their system. We would also recommend Daily As-Used Demand rates for each season, recognizing that summer is likely to have the highest rates.

We recommend that the Commission to direct the utilities to make the super-peak charge as granular as possible, both from a location and time perspective. We recognize that in certain utility systems, there may be minimal variation across certain parts of the territory. But a more granular approach will best align with cost causation principles.
Conclusion

We commend Staff for being responsive to stakeholder concerns and for proposing modifications to the existing Value of DER tariff to mitigate some of the disruptions that are occurring in the market. We appreciate the Commission’s consideration of our comments and request that it adopt the recommendations contained therein.