June 10, 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 of Technical Conference*, dated April 22, 2016, in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Senior Director, Industry Analysis

Response to "Notice of Technical Conference" (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 (AEE Institute), 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, AEE Institute applauds the New York Commission for opening this proceeding on Reforming the Energy Vision (REV), which seeks to unlock the potential of advanced energy 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 *Notice of Technical Conference* (the "Notice"), issued on April 22, 2016, in Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources, AEE Institute 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 create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions.

Introduction

On December 23, 2015, the New York Public Service Commission ("Commission") issued its *Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference* under Case 15-E-0751, with proposals due by April 18, 2016. In response to this notice, a detailed proposal was filed by AEE Institute, ACE NY and NECEC in consultation with Clean Power Research.[1] Subsequently, on April 22, 2016, the Commission issued a *Notice of Technical Conference* (the "Notice"), in which it announced a technical conference for May 10, 2016, and also gave parties an opportunity to file additional written comments by June 10, 2016. Based on AEE Institute's participation at the May 10 technical conference and based on the filings of other parties, we present here some additional comments for the Commission's consideration. However, based on the Commission's May 25, 2016, Procedural Ruling in this case, in which it decided to move forward with an "informal and collaborative process to develop, to the extent possible, joint recommendations for Commission action," these comments are limited, and address the following:

- Proposed modifications to our original proposal
- Selected comments on other filings
- Recommendations for the stakeholder process

Proposed Modifications to the AEEI/ACE NY/NECEC LMP+D Proposal

In response to the original December 23, 2015 Notice, we developed a detailed LMP+D proposal that could be implemented relatively quickly (e.g., it does not require AMI) and that would apply to all DER technologies equally – two characteristics that we believe are central to the Commission's reasons for initiating this LMP+D proceeding. Based on statements from DPS Staff at the May 10 Technical Conference regarding their objectives for the interim methodology, it is apparent to us that the vision for the interim methodology is more modest than what we proposed in our April 18, 2016, filing. Moreover, at the Technical Conference there were some questions posed to us regarding treatment of embedded costs (past costs not avoidable with DER) and whether or not our proposed LMP+D rate would be a full-fledged rate or something that could be implemented as a rider to existing rates. Furthermore, while we still believe that our proposal represents a viable option for an interim successor to net energy metering

[1] Clean Power Research is a software and consulting company based in Napa, California, engaged by AEE Institute to assist in the development of this response.

(NEM), and not just a long-term option, we provide here some additional information and options for the Commission's consideration within the context of developing the interim methodology.

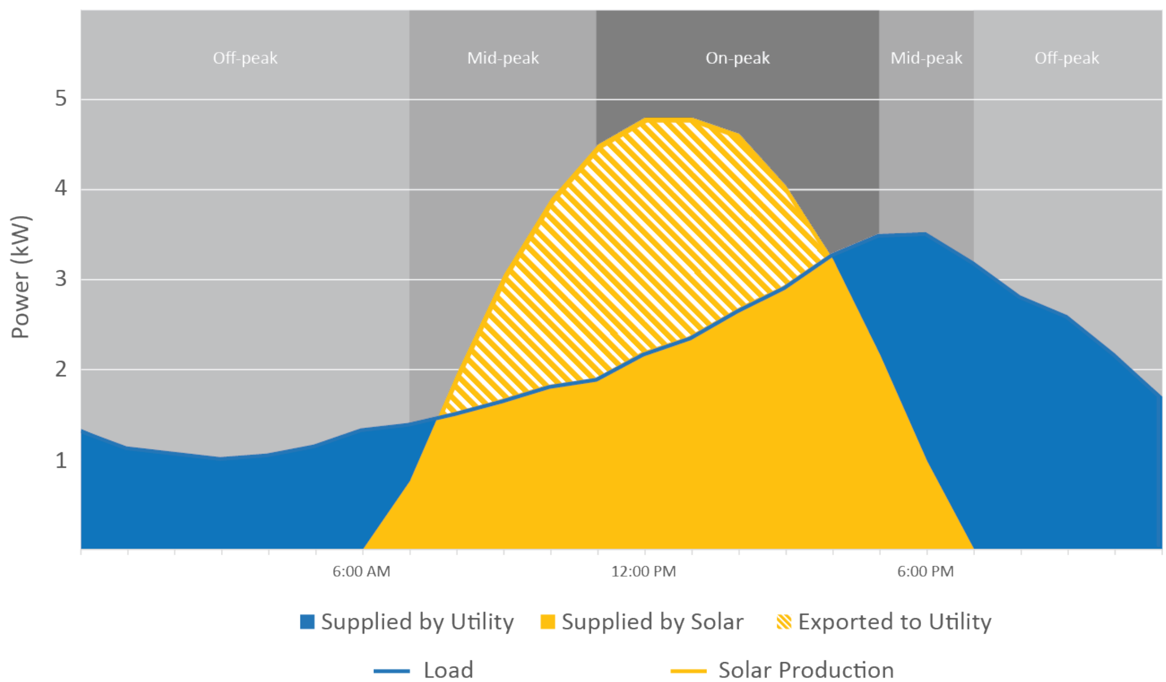
LMP+D Rate versus DER Rider

Our original proposal was intended to serve as a new rate applicable to all types of DER. However it could also be adapted as a "DER Rider" that would apply primarily to DG, but also potentially to energy storage with export capability. Under the DER Rider approach, customers would continue to take service under their existing retail rate, and the methods for determining hourly prices (as described in our original proposal and its appendix) would be applicable to distributed generation delivered (exported) to the grid. Thus, the DER Rider would govern how credits would be calculated and applied to the customer's bill.

The DER Rider would be applicable to net generation exported to the grid, i.e., the portion of energy delivered from behind-the-meter (BTM) resources whenever generation exceeded customer load. Self-consumption (BTM generation produced and consumed by the customer without passing through the metering point) would be neither charged nor credited, and thus, from the customer's perspective, would effectively be valued at the applicable retail rate, as is the case with BTM DG today. This modification would make our proposal similar in structure to the proposal filed by the Solar Energy Industries Association (SEIA) and Vote Solar, except that all exported generation, and not just monthly net excess generation (NEG) would be valued at the hourly LMP+D rate. This would encourage DG to be dispatched when it was most valuable, and would also encourage customers to pair DG with energy storage and/or load management, to maximize exports at time of highest prices, when these resources could provide the most value to the grid. This modification to our original proposal would also simplify the work of the Commission by using existing, approved rates for consumption that ensure collection of embedded costs and by limiting LMP+D calculations to only energy delivered to the grid. It would also add more price predictability for DER owners.

In the illustrative figure below (using solar as the example), consumption (solid blue) is supplied by the utility and would be charged based on the applicable retail rate. Self-consumption (solid yellow) is energy that is generated behind the meter but consumed on-site without ever passing through the meter to the Distributed System Platform (DSP), and is neither charged nor credited by the utility. Export energy (hashed yellow) is energy that is generated behind the meter in excess of load. This energy registers as export energy at the meter and is delivered to the DSP. The DER Rider would credit this energy based on the LMP+D locational price for the hour of export. Note that in some hours it is possible that both imports and exports may be measured. These would be treated separately. Imports would be charged at the applicable retail rate and exports would be credited at the applicable LMP+D rate, using bill crediting as the mechanism, as is done today with NEM.

This DER Rider approach would require metering that is different from existing NEM meters, but would not require AMI. It would require separate, hourly logging of imports and exports because the LMP+D pricing is hourly. As described in our original proposal, this could be accomplished with existing interval metering technology.



The methods to quantify these credits would be the same for both BTM exports, as described above, as well as for dedicated generation resources without load or with *de minimus* load, such as community shared resources. Therefore, the DER Rider could be used to handle both BTM generation and dedicated generation resources.

This approach would further establish that embedded costs are paid through normal rates for consumption. A customer with BTM generation would continue to pay for embedded costs based on their applicable retail rate (whether through monthly customer charges, volumetric charges, or demand charges).

On the other hand, DG sources without load, such as shared resources, would not pay for embedded costs. Such a supplier may pay nominal interconnection and metering costs, but would not pay for the embedded costs of the DSP. This would be similar to the case of central-station suppliers feeding into the NYISO market who do not pay for DSP costs, even though the DSP is required to ultimately bring their product to market. Thus, all embedded costs and future costs required to update and maintain the DSP would be paid solely by load customers, as is the case today.

The DER Rider could be used with any approved rate, whether residential, commercial, or industrial. The existing rate would address pricing of all consumption, while the DER Rider would address the crediting mechanism for all energy delivered to the grid.

Load Allocation of Embedded Costs

Our original proposal focused on the design of the variable components of the LMP+D rate, but acknowledged that "embedded" (not avoidable) costs should be recovered from LMP+D customers. Embedded costs include those costs that the utility has already incurred and are therefore not avoidable with DER. Recovery of embedded costs could include a monthly customer charge, however we did not fully address the overall structure of the LMP+D rate, leaving the implementation details to the Commission.

There are a number of options for collecting embedded costs. They could be collected through the use of existing rates (see the DER Rider discussion above). They could also be collected on a load-weighted hourly basis (based on the utility's load) by using concepts and methods that we proposed for computing the LMP+D rate in our original proposal. The reasons that the Commission may wish to consider such a load-weighted approach to allocating embedded costs is to provide additional impetus to consumers to shift loads away from times of peak loading.

So, there are four basic approaches to recovering embedded costs:

1. Monthly customer charge ($ per month, as is done today in New York for some of these costs)
2. Volumetric charge ($ per kWh, as is done today for some of these costs)
3. Demand charge ($ per kW of peak non-coincident customer demand, as is done today with demand-billed customers)[2]
4. Load-weighted hourly charge ($ per kWh, price varies by hour)

The first three options are consistent with current ratemaking practices in New York. The fourth option would further encourage consumers to reduce on-peak usage based on pricing that reflects the actual system needs. By shifting load away from times of highest demand, LMP+D customers would be

[2] We are not proposing that demand charges be imposed on customers who currently are not demand billed. We also generally favor coincident peak demand as a way to structure demand charges so that they are more in line with cost causation.

able to reduce their bills, similar to the way customers on flat volumetric rates can reduce their bill through reduced usage, and demand-billed customers can reduce their bill through lowering non-coincident demand.

This option also requires the measurement of hourly consumption, but hourly metering was already a requirement in our original proposal. The meter used for LMP+D consumers with BTM generation would have to measure hourly (or sub-hourly) integrated energy exports and imports separately. Imports would be charged at the applicable hourly rate (which would include load-weighted embedded costs) and exports would be credited at the applicable hourly LMP+D rate.

Unlike with the DER Rider concept described above, which is applicable only to DG, this approach would apply to all forms of DER because the benefits derived from shifting load away from peak load times could also be captured by LMP+D customers without generation. For example, customers who opt in to the LMP+D rate would have hourly pricing for their embedded costs plus hourly pricing for their variable costs, as described in our original proposal.

The hourly charges would be designed so that all of the embedded costs would be recovered through the use of a load-weighted hourly price. The average customer[3] would pay the same annual amount whether on the standard retail rate or the LMP+D rate:

Example Residential Customer	**Collection of Embedded Costs**
1. Standard customer, average annual energy usage	Average residential revenue
2. Standard customer, 30% above (below) average annual energy usage	30% above (below) average residential revenue
3. LMP+D customer, average annual <u>load-weighted</u> energy usage	Average residential revenue
4. LMP+D customer, 30% above (below) average annual <u>load-weighted</u> energy usage	30% above (below) average residential revenue

To the extent that a customer on standard rates reduced consumption of kWh or kW, as the case may be, they would be able to avoid these charges, as is the case today when customers improve their energy efficiency or, if subject to demand charges, can shift demand. To the extent that an LMP+D customer reduced energy usage during the peak, they would similarly be able to avoid these charges.

Regardless of the design of the mechanism selected to recover embedded costs, a customer with BTM generation should still be able to earn credits that could be applied against these charges.

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[3] By average customer, we mean a customer with average monthly usage and a "typical" load shape that is representative of that customer class.

Interim Hourly Price Simplification

Our original proposal described methods for calculating *ex-post* hourly prices. It also included several options for providing additional price predictability/stability so that LMP+D customers and DER providers would be able to raise capital to finance new DER investments. However, for the interim methodology, this could be further simplified if desired by the Commission as follows.

The essence of the hourly price is to assign a representative value to electricity supply based on load. A simplified way to do this is to develop a pricing schedule, such as the illustrative schedule below:

Variable (hourly) Pricing Schedule for Location X (Illustrative)

Total Service Territory Load (MW)	Price ($ per kWh)
0-1,000	$0.105
1,000-2,000	$0.112
2,000-3,000	$0.126
etc…	etc…

This pricing schedule only includes the potentially-avoidable costs as described in the BCA Framework Order, such as wholesale costs and future distribution costs. It does not include the embedded costs described in the previous sections above, as these are treated differently. The table would be developed using an analysis of a sample year or years (e.g., the previous calendar year), similar to the proposed "back-calculation" of historical prices for informational purposes that we included in our original proposal. These prices would then be binned by load to create the table.

The table would be set for a period of time, such as one year, and updated annually for each location. This would not only simplify the computation of electricity bills, but it would also provide price stability, recognized as a need in the proposal. Further stability could be provided by setting the schedule for a longer term, such as five years or 10 years, with levelized values that incorporate the effect of escalation.

Selected Comments on other Filings

As noted above, given the Commission's decision to pursue an informal, collaborative stakeholder process going forward, we have chosen to limit our written comments on other proposals. We would note that several proposals articulated similar principles to ours, including those related to grandfathering, gradualism, and fair valuation of DER benefits. Several proposals focused on incremental changes to the existing NEM framework, such as the proposal from SEIA/Vote Solar. Their proposal would work within the existing NEM framework and apply initially to DG only, and more specifically to solar. For DG, the concept of a DER Rider to begin to implement LMP+D has merit, and as described above, we have considered this concept within the context of revising our original LMP+D proposal, which shows how it would be possible to implement a DER Rider rate along the lines of what SEIA/Vote Solar have proposed and then add locational and temporal granularity along the lines of our proposed methodology.

We do note, however, that the SEIA/Vote Solar proposal, along with most of the other proposals did not address how LMP+D would in fact be calculated. Conversely, we believe that we have submitted the most detailed proposal in terms of how one would go about calculating LMP+D and, consistent with other goals of the Commission, have considered how this would apply to all DER technologies. For the most part we did not see any full proposals that we would consider incompatible with ours, and thus, our proposal could easily be considered alongside some of the other proposals that have focused more on the interim framework and less on actual valuation.

We would also note that the E3 report,[4] prepared for NYSERDA, independently developed a very similar rate design to ours, and we think there is merit in looking more closely at how the two could potentially be combined.

Solar Progress Partnership Filing

AEE Institute commends the Joint Utilities and SolarCity, SunEdison, and SunPower for working together to come up with a joint proposal on how to structure an orderly transition away from net energy metering in New York State. We are keenly aware of the amount of time, effort, and resources each party invested in this process, and we are hopeful that the Solar Progress Partnership is the beginning of greater solar-utility collaboration in New York State and across the country.

AEE Institute is in the unique position of having facilitated the dialogue among the members of the Partnership, which included only limited participation of AEE members in the form of three solar companies. While AEE Institute is pleased to have facilitated the Partnership discussions, AEE Institute, along with ACE NY and NECEC, is committed to representing the views of the entire advanced energy community, and our comments here reflect the positions of that broader community and the diverse technologies and businesses that are represented within it. We see merit in the Solar Progress Partnership filing as a transition mechanism, but believe that some modifications and clarifications are needed to improve its effectiveness.

[4] E3, *Full Value Tariff Design and Retail Rate Choices*, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, April 18, 2016

Value of LMP+D+E:[5] We acknowledge that the Partnership filing is not prescriptive of the value of LMP+D+E and that it does not explicitly state whether that value is greater or lower than the retail rate. However, the graph used within the filing, the presence of a Transitional Gap Credit, and the unidirectional nature of the Developer Payment only work in scenarios where the value of LMP+D+E is lower than the retail rate. Many CDG projects may have greater value, especially if they are located in constrained areas and can operate coincident with local demand peaks. The "D" value in these cases may be significant. Any transition mechanism adopted by the Commission should clearly spell out how these projects will be compensated by the utility in the event that the value of LMP+D+E is greater than the retail rate. This could include bidirectional Developer Payments (or a Utility Payment as the case may be) or separate utility contracts covering the value that allows the utility to incorporate the facility into their distribution planning needs.

Developer Payment: Solar companies should retain the ability to decide the type of business model that works for them and how to interact with their customers. The use of a Developer Payment in order to maintain a customer bill credit at the retail rate for energy exports will likely be an attractive option for many developers so that they can continue to sell a product that is easy for their customers to understand. However, some solar companies may prefer to forgo the Developer Payment to simplify transactions with customers and the utility, in which case their customers would receive a credit at LMP+D+E (plus the Transitional Gap Credit, as applicable) for energy exports instead of a retail rate credit. This would alleviate those companies of the need to provide a line of credit or other financial assurance to the utility to protect against a default in Developer Payments.

Equity between Community and Onsite Projects: The Partnership proposal would begin to subject CDG projects to a Developer Payment in the near term, effectively reducing compensation from retail rate net metering for these projects, which will serve customers unable to install onsite projects including renters, low-income communities and others unable to install onsite projects for a variety of reasons. Onsite projects, on the other hand, would receive full retail rate net metering until 2020 under the Partnership proposal. This creates a disparity in compensation between customers who subscribe to CDG and customers who are able to install onsite projects over the next three years. The Commission should take care to not create a situation where it significantly advantages one type of project over another, as both project types are ultimately intended to benefit ratepayers. While we recognize the concern of the Partnership about the rapid expansion of the interconnection queues, we encourage the

[5] While we usually refer to LMP+D to represent the full value of DER to the system, we will use LMP+D+E in the discussion of the Partnership filing to maintain consistency with the nomenclature used within that filing.

Commission to avoid creating a "boom and bust" situation for CDG, which has the potential to provide New Yorkers with access to clean energy who are not able to install on-site DG.

Non-Solar Projects: We want to make sure that the Commission understands that the Partnership focused solely on solar projects, which currently represent the bulk of the market. Other technologies should not be subject to the proposed mechanism. Should the Commission be interested in considering similar structures for other DER technologies, it will be important to engage the full range of DER providers in those deliberations.

Transition periods: On page 16 of the Partnership proposal, two different transition methods were proposed (the ramp down period from retail rate compensation to LMP+D+E compensation) for onsite solar installations. The JU proposed a three-year transition whereas the solar companies proposed a transition using five blocks, based on capacity. In our original AEEI/ACE NY/NECEC proposal we distinguished between onsite DG projects that were net importers and net exporters. We further proposed that retail rate NEM remain the default option for net importers and that LMP+D become the default for net exporters. However, if the Commission were to adopt a transition plan as outlined in the Partnership proposal that does not make this type of distinction, the advanced energy community prefers the approach of using MW blocks.

Queue Management: On page 12 of the proposal, the Partnership proposed that once the utility informs a community solar developer of their provisional position in the queue, that the developer would have 30 days to respond to whether they want to remain in the queue or withdraw. However, there is no similar time period placed upon the utilities to address queue management, with the proposal simply stating that the utilities would inform developers of their queue position "soon after program initiation." The language regarding the utility timeline and obligations needs to be clarified and we would suggest utilities should be required to process applications within a defined time period.

More generally, several members of the advanced energy community expressed concerns about the proposed prioritization of projects in the interconnection queue. We recognize that this is a complex issue that is also subject to other Commission orders, so we simply state here that the process of queue management needs to be fair and equitable and consider the full range of project types and developer types.

Recommendations for the Stakeholder Process

Now that the Commission has decided on a collaborative stakeholder process for developing the interim methodology, we urge the Commission to structure it in such a way as to facilitate participation by the advanced energy community. Specifically, it must be flexible enough to allow advanced energy companies and stakeholders, such as AEE Institute, ACE NY and NECEC, to share staff and resources, as many firms have far fewer resources than the utilities for participation in such processes, and are often also engaged in other state grid modernization discussions that require staff resources.

As a general comment on the scope of the collaborative process, we think that the value of the stakeholder process will be to develop high-level objectives and principles. To the extent that these principles are agreeable across parties and to the Commission, the Staff could then develop the details of a more formal methodology using the inputs provided by us and others as a starting point.

Conclusions

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. These comments, offered in response to the Commission's April 22, 2016, Notice, are meant to further the development of a suitable successor to NEM and to meet the Commission's objective of fully valuing all types of DER. We look forward to our continued participation in this proceeding.