UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Old Dominion Electric Cooperative v. PJM Interconnection, L.L.C.	)	Docket No. EL17-32-000
Advanced Energy Management Alliance v. PJM Interconnection, L.L.C.	)	Docket No. EL17-36-000

POST TECHNICAL CONFERENCE COMMENTS
OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to the Notice Inviting Post-Technical Conference Comments issued June 13, 2018, in the above proceeding, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM Interconnection, L.L.C. ("PJM") ("Market Monitor"), submits these comments.[1]

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[1] Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT") or the PJM ("OA").

I. COMMENTS

A. Seasonal Load Variation & Alternate Market Designs

1. Some panelists indicated that the current annual construct and existing aggregation rules result in a barrier to entry. Please comment on whether or not there are barriers to entry and provide any supporting information, such as unmatched MWs of capacity. Could this be fully addressed by improving or modifying aggregation rules? If not, what other changes would be required? What would be the downside of modifying such rules?

Capacity defined as an annual product is not new. Capacity has been an annual product in PJM since at least the 2007 introduction of the Reliability Pricing Model ("RPM"). Defining capacity as an annual product in the RPM was a core element of the RPM reforms that revised the capacity market design and permitted the capacity market to work to contribute to market incentives to enter and exit the market as well as to invest in existing assets. Capacity continues to be defined as an annual product after the Capacity Performance reforms ("CP").

The recognition of the locational nature of capacity resources was another core element of the RPM reforms. Any form of aggregation that attenuates the locational definition of capacity resources should be rejected as inconsistent with the purpose of a locational capacity market.

The annual capacity market design has worked well to incent entry and exit. To the extent that load is paying too much for capacity, the single largest consistent factor resulting in inflated capacity prices has been PJM's forecasts. The IMM has also identified other design issues that can be addressed relatively quickly and efficiently compared to redesigning the capacity market to be a seasonal market.[2]

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[2] See IMM report: "Analysis of 2020/2021 Base Residual Auction," http://www.monitoringanalytics.com/reports/Reports/2017.shtml (November 17, 2017).

Barriers to entry exist when new entrants have to pay costs that incumbents do not have to pay and which create the ability for incumbents to raise prices above the competitive level.

It is not a barrier to entry to require all products sold in the capacity market to be substitutes. In fact, this requirement is a precondition to having a competitive market and a competitive outcome. In order for all products sold in the capacity market to be substitutes, all products must be defined in the same way, including that all products be annual (given that the design is annual) and have comparable performance requirements.

It is not a barrier to entry to recognize the locational differences in capacity supply and demand. This requirement is a precondition to having a functioning capacity market that provides price signals consistent with the actual supply and demand of resources and the transmission constraints in the network.

The fact that there was a significant level of annual DR offered and cleared in the most recent capacity market auction illustrates that there are not meaningful barriers to entry and demonstrates that DR can participate as an annual product. The total amount of DR offered into the 2021/2022 BRA was 11,886.8 MW, of which 11,094.6 MW, 93.3 percent, were annual. Of the 11,125.8 MW of DR cleared in the 2021/2022 BRA, 10,673.5 MW, 95.9 percent, cleared as annual capacity and 452.3 MW cleared as summer seasonal capacity. The total amount of DR offered into the 2021/2022 BRA increased by 20.7 percent from the 2020/2021 BRA.

2. **According to the 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) report, cleared megawatt quantities of wind, solar, demand response, and energy efficiency resources all increased compared to the 2020/2021 RPM BRA and at higher clearing prices throughout the PJM footprint. Please comment on how these results reflect on the efficacy of PJM's seasonal aggregation mechanism and the ability of these resource types to participate in RPM as either annual resources or aggregated resources under existing RPM rules. To the extent you view one or more of the alternative market designs mentioned above as better than the existing RPM rules, please explain how those alternative designs would yield preferable auction outcomes relative to those seen in the 2021/2022 BRA. Please provide evidence and quantitative support where possible.**

See the response to question 1. The results of the 2021/2022 BRA demonstrate that there is no reason to create a seasonal capacity market.

3. **Under either a two-season or three-season market construct, how would PJM optimize capacity procurement within and across seasons? Would each season have a distinct demand curve and auction that clears independently of other seasons, or would all seasonal auctions be cleared simultaneously to optimize procurement for a delivery year?**

The auctions should be cleared simultaneously in order to efficiently capture the interactions between the seasons and produce a competitive outcome reflecting all the constraints and the differentiated supply offers.

For a two season market, there would be different demand curves and different supply curves for each season and units could participate in one or both seasons. To accommodate resources with varying offer constraints, resources could offer as annual or summer or winter capacity. Resources offered as annual capacity would be required to clear to meet both summer and winter capacity requirements.

4. **During the technical conference, Mr. Falin of PJM noted that PJM performs a winter-period peak load test known as a Capacity Emergency Transfer Objective and Capacity Emergency Transfer Limit (CETO CETL analysis). Mr. Falin explained that during the winter-period CETO CETL analysis, PJM divides its region into sub-regions and tests how many MWs of emergency imports are needed to satisfy reliability criteria given that specific sub-region's quantity of installed reserves. Please describe the assumptions that PJM makes when it performs a CETO/CETL analysis for winter-period peak loads. What assumptions are markedly different from summer-period peak load CETO/CETL analyses? Does PJM perform winter- and summer-period CETO/CETL analyses for all sub-areas or LDAs?**

No response.

5. **What other implementation challenges would be involved in transitioning to a two-season or three-season market construct (aside from a lengthy stakeholder process)?**

The implementation challenges are much more complex than they would appear. The challenges include but are not limited to:

Defining ex ante reliability needs by season. The PRISM model gives a misleading idea of the precision of the ex ante calculation of reliability needs by season. The PRISM model can provide very precise calculations that are quite wrong. It is misleading to believe that there is a good analytical basis for determining that PJM does not need 17,000 MW of capacity in the winter compared to the summer.

There are a number of assumptions underlying the PRISM model which are inaccurate. PRISM assumes that DR is a perfect substitute for capacity performance resources. PRISM assumes that wind resources are a perfect substitute for thermal capacity performance resources. PRISM assumes that solar resources are a perfect substitute for thermal capacity performance resources. PRISM assumes non-correlated unit outages. While PJM has made an ad hoc adjustment for the winter season, there has been no recognition that DR outages are correlated, wind outages are correlated, solar outages are correlated and at times gas outages are correlated.

PRISM does not account for DR fatigue. DR fatigue is the phenomenon that after multiple days of very high temperatures for example, or very low temperatures, demand response tends to be less willing to interrupt. PRISM does not account for units at risk, or more generally for entry and exit. PRISM does not account for common mode failures. PRISM does not account for any risks associated with increased reliance on gas as a fuel in the winter.

It is not clear how PRISM defines being scarce and losing load. Is it when generation is actually less than load? Or does PRISM include spinning reserve in the definition of load when defining loss of load? Does PRISM include primary reserve in the definition of load? Does PRISM include secondary or 30 minute reserves in the definition of load? How does PRISM account for operator actions? How does PRISM deal with voltage reductions and is there loss of load when PJM implements emergency actions like voltage reductions? How does PRISM account for the new definitions of scarcity, e.g. the ORDC curve, the new reserve targets, and locational scarcity?

This short list is only representative of some important factors that are not addressed in PRISM. Developing and implementing a dramatic change to the capacity market design is not just a simple mechanical change as it has been characterized. Such a change would be complicated and has very significant longer term implications.

All the assumptions incorporated in the PRISM model about exactly what happens during the summer and winter need to be addressed. Implementing a seasonal capacity market is much more complicated than the simple and apparently intuitive assertion that we have a need for some extra capacity in the summer that can be met through summer resources. PRISM is a planning model and ignores operational features of the market. A key implementation challenge is to define in an accurate way the actual need for capacity on an annual and, if possible, a seasonal basis, accounting for the real world complexities that will determine whether a seasonal capacity market can really work.

It would take a significant amount of time to redesign the capacity market so that it really worked on a seasonal basis. There is no guarantee and not even a well founded expectation that the change would result in a reduction in the cost of capacity. Some proponents of a seasonal capacity market appear to believe that it is intuitively obvious that it would result in a significant reduction in the cost of capacity. It is not.

The goal should be to ensure sustainable and competitive market results over both seasons. Additional questions include: What is the definition of performance assessment hours in a seasonal construct? What are the offer caps in a seasonal construct? What are the impacts on the energy markets? Will a seasonal construct result in fewer MW of capacity resources and higher energy prices? What is the net or total impact of higher energy prices and any changes in capacity prices? What are the impacts from energy and capacity markets on the incentives to invest in units, maintain units and retire units? What would it mean if most or all of the asserted incremental demand for capacity in the summer were met by DR, recognizing that whenever DR is called it results in a performance assessment hour or interval? Does a seasonal market increase risk for developers of generating plants?

B. Peak Shaving

1. **During the technical conference, Mr. Falin of PJM indicated that PJM has put on hold possible changes to the PRD program to align the program with PJM's annual capacity construct. Is PRD a feasible path forward for incorporating seasonal DR resources in the capacity market? Please explain why or why not.**

Yes, if the program is a true PRD program. The PRD program has morphed a great deal from its original form. The ideal PRD design would have had DR outside the market, but with a commitment to respond. The current PRD design is not a feasible path forward. The current PRD design has DR offer in the capacity market, with a commitment to respond to LMP but not to emergency events. In the ideal design, DR would not offer in the capacity market, PJM would reflect the PRD related reductions in the load forecast and there would be a commitment to provide the reductions. The ideal PRD approach is a feasible path forward that would make DR effective and reliable and that would not require DR to comply with the details of the capacity performance rules in order to participate. PRD resources would not directly participate in the capacity market but would commit to reduce load under defined conditions. PJM would not add back the reductions to its load forecast and PRD would be paid immediately as a result of reductions in load and the associated requirement to purchase capacity. But there is no reason to focus on PRD currently as the SODRSTF (Summer Only Demand Response Senior Task Force) is currently developing a PRD like product.

The SODRSTF is currently discussing a related proposal under which PJM would reduce its load forecast based on the expectation that specific load reduction actions would be taken when triggered by a THI threshold. The basic structure of the SODRSTF approach is a feasible path forward. Some of the details currently in PJM's version need to be resolved. The SODRSTF can be thought of as the successor to the ideal PRD design.

In general, the proposed program has the positive features of being outside the capacity market and the requirements of capacity resource status, being dynamic and flexible, having identified triggers for reducing load rather than requiring and/or triggering an emergency and directly and immediately affecting the PJM load forecast. Some issues that need to be addressed include how to measure the impact of the programs by relying on metered load and the load on which capacity costs are allocated (PLC), ensuring that the benefits get to individual customers based on their actions in response to identified programs, and ensuring that the programs are open to all administrators including CSPs and not only monopoly EDCs.

Well designed programs like this would permit summer only demand response to work effectively without requiring a significant restructuring of the PJM capacity market to include seasonal markets.

SODRSTF type programs would permit more effective peak shaving by customers and permit more dynamic and effective participation of demand side in the PJM markets. The fact that these programs would be outside the capacity market does not mean that they would be outside the PJM markets. These programs would be part of PJM markets without being tied to the detailed rules of the capacity market. These programs would appropriately permit demand side to be an economic resource rather than treated as an emergency resource. These programs would permit demand side to be demand side, consistent with all other markets, instead of pretending to be supply side resources.

The use of a THI trigger would also more realistically reflect high demand days when PJM needs demand reductions rather than relying on the clearly inaccurate and anachronistic reliance on a single coincident peak demand day (1 CP) as the metric for triggering demand side and for triggering the obligation to pay for capacity.

2. **During the technical conference, Mr. Falin stated that, in order for peak shaving activity to be reflected in load forecasts, peak shaving actions will need to be based on specific triggers, and commit to be interrupted a certain number of times per summer with a certain hourly duration. Direct load control programs operated by electric distribution companies that cycle air conditioners or other appliances typically have these attributes specified in their tariffs. What is the status of the recognition of these programs in PJM's load forecasts? Please describe the mechanisms, calculations, and adjustments that PJM uses to account for load serving entity (LSE) or electric distribution company (EDC) direct load control and load management programs in PJM load forecasting. Are these load forecast adjustments performed at the request of the EDC, or are there clear and specific procedures or rules that are applied non-discriminatorily to all LSE and electric distribution company direct load control and load management programs?**

Peak shaving activity by PJM market participants are incorporated in the PJM load forecast because they affect measured load. PJM would have to improve its forecasting capabilities in order to define the impact of SODRSTF programs on demand and the forecasted load. PJM would also need detailed definitions of the programs and program response as inputs to the forecasts.

3. **During the technical conference, Mr. Falin stated that PJM conducts its load forecast modeling, and calculates model forecast accuracy, at the PJM system level. Mr. Falin also stated that PJM compared forecasted zonal load to average historical contribution of each zone to the PJM's overall peak and that number is within a tenth or two-tenths of a percent of PJM's zonal forecast. Did PJM observe any differences in the model errors by zone, especially for the zones that have operated summer-focused load management programs for years? How does the frequency of summer-focused load management programs' deployment, especially their infrequent deployment during system peaks, impact PJM load forecasts and the calculated model errors at the zonal level?**

PJM will need to improve its approach to forecasting including the ability to forecast zonal load in order for the SODRSTF approach to work.

4. **According to information provided in the AEMA complaint in Docket No. EL17-36-000, Baltimore Gas & Electric (BG&E) worked with PJM in Maryland Public Service Commission Rate Case No. 9406 to reflect its air-conditioner direct control program into an alternate load forecast for its zone, but not at the full load reduction that the program can produce. Please describe the processes involved in creating that alternative load forecast and the assumptions underlying BG&E's partial adjustment.**

No response.

5. **In PJM's June 2017 white paper "Demand Response Strategy", PJM stated "Ideally, PJM would have a truly unrestricted peak-load forecast with a complete understanding of explicit (dispatch and/or managed by PJM) versus implicit (managed by LSE, EDC or end-use customer) DR, allowing more visibility to quantify forecast risk." Please describe the steps PJM is taking to accomplish this goal. Are these steps sufficient to accomplish this goal? Why or why not? How is PJM working to change its load forecasting methodology to achieve this goal?**

The SODRSTF is currently discussing how to implement implicit DR, recognizing that PJM would require a thorough understanding of each program managed by an LSE, EDC, CSP or customer. With complete information on each program, most importantly including metered data on the participating customers, PJM can accurately determine the impact on the load forecast. Each program should be modeled separately in order to allow PJM a greater ability to assess the impact on the forecast with maximum accuracy.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: July 13, 2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 13th day of July, 2018.

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