UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Advanced Energy Management Alliance v. PJM Interconnection, L.L.C.	)))	**Docket Nos. EL17-36-000**
Old Dominion Electric Cooperative, et al. v. PJM Interconnection, L.L.C.	)))	**EL17-32-000**

POST-TECHNICAL CONFERENCE RESPONSE TO QUESTIONS OF PJM INTERCONNECTION, L.L.C.

I. EXECUTIVE SUMMARY

Pursuant to the Notice Requesting Post-Technical Comments issued by the Federal Energy Regulatory Commission ("Commission") on June 13, 2018, PJM Interconnection, L.L.C. ("PJM") submits the following comments. As further explained in response to the Commission's questions, the current aggregation rules sufficiently enable participation of seasonal resources in PJM's Capacity Market. More particularly, as evidenced by the recent 2021/2022 Base Residual Auction results, a near record amount of seasonal resources offered and cleared in the Capacity Market. These results demonstrate that the recently adopted enhanced aggregation rules are working to enable seasonal resources to participate in a robust and meaningful manner. Consequently, it is unnecessary and imprudent to make significant modifications to the Capacity Performance construct at this time.[1]

[1] Moreover, as noted below, procuring capacity on a seasonal basis when most of the rest of the nation procures and compensates capacity on an annual basis, would create its own set of seams issues and skewed investment signals as between PJM and other regions. As a result, any such change, which would involve resetting of how the installed reserve margin is calculated and how capacity is procured, should be explored, if at all, on an interconnection-wide if not national basis so that all of the implications of such a change can be analyzed.

II. RESPONSE TO QUESTIONS

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?***

The current annual construct and existing aggregation rules under the Capacity Performance[2] construct does not result in a barrier to entry for resources that are unable to perform on an annual basis. The most telling evidence for this conclusion can be found by looking at the results of the 2021/2022 BRA which was run after the opening of this Commission inquiry. The 2021/2022 Base Residual Auction ("BRA") cleared a higher cumulative megawatt quantity of wind, solar and Energy Efficiency ("EE") resources as aggregated seasonal resources than any prior BRA. Further, the megawatt quantity of Demand Resources ("DR") that cleared in the 2021/2022 BRA was the highest level that cleared in a BRA since the 2016/2017 BRA. This fact alone shows the fear that DR cannot effectively participate in the capacity market is misplaced.[3]

In addition, the total MW quantity of aggregated resources cleared has nearly doubled with 715.5 MW that cleared in the 2021/2022 BRA, compared to the 397.9 MW that cleared in the 2020/2021 BRA. As shown in the table below, the total MW quantity of summer-period

[2] For the purpose of this answer, capitalized terms not defined herein shall have the meaning as contained in the PJM Open Access Transmission Tariff ("Tariff"), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., ("Operating Agreement") or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA").

[3] Specifically, the total MW quantity of DR that cleared the 2021/2022 BRA was 11,126 MW (10,673.5 MW as Annual DR and 452.3 MW as summer-period DR) compared to a total cleared MW quantity of DR in the 2016/2017 BRA of 12,408.1 MW (9,849.5 MW as Limited DR, 2,470 MW as Extended Summer DR and 88.6 MW as Annual DR). The offered and cleared megawatt quantity of each resource type from all RPM BRAs is located at: http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx?la=en.

capacity (for example, solar and summer-only DR) that offered into the BRA was 1,204.2 MW and 715.5 MW cleared the auction. Hence 715.5 MW of Capacity Resources that would not by themselves have qualified as stand-alone annual capacity resources were able to participate by aggregating with winter period capacity (for example, wind) and take on a capacity commitment because of the existing aggregation rules.

	2021/2022 BRA					
	Offered UCAP MW			Cleared UCAP MW		
	Annual	Summer	Winter	Annual	Summer	Winter
Gen	170,841.5	106.2	715.5	149,615.6	53.9	715.5
DR	11,094.6	792.2	0.0	10,673.5	452.3	0.0
EE	2,649.0	305.8	0.0	2,622.7	209.3	0.0
	184,585.1	1,204.2	715.5	162,911.8	715.5	715.5

Significantly, only 488.7 MW of such resources did not clear in the auction, mainly because of an insufficient MW quantity of Sell Offers from winter-period capacity resources needed to support additional clearing of sell offers of summer-capacity resources. However, given the continued penetration of wind resources,[4] it is likely that winter-only resources will continue to increase and better match the available summer resources in the coming years.

Overall, the results of the latest BRA is strong evidence that the current annual construct and existing aggregation rules provide for robust and meaningful participation in the capacity market by both annual and seasonal resources. Moreover, the upward trend in cleared seasonal capacity is promising and confirms the Commission's recent determination that the enhanced aggregation rules "may allow greater participation in the RPM market by Seasonal Resources."[5] PJM expects this trend to continue as Market Participants adapt to and create innovative

[4] There are currently more than 4,000MWs of wind generation under construction within the PJM Region and an additional 16,000MWs of wind generation in the PJM interconnection queue and under study.

[5] *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,159 (2018).

approaches to being annual resources as required under PJM's Capacity Performance rules.[6] Thus, PJM does not see the need for additional modifications to the aggregation rules at this juncture.

2. ***According to the 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) report,[7] 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.***

As explained in response to Question 1, the annual requirement along with existing aggregation rules do not result in a barrier to entry. As evidenced by the 2021/2022 BRA results, all 715.5MWs of winter resources that offered into the BRA cleared. While 489 MWs of summer resources did not clear, this represents only 0.3% of the total 163,627 MWs of resources that cleared. In comparison, 21,673 MWs of annual resources did not clear the BRA, which represents a much greater percentage -- 13% -- of the total cleared resources. The simple fact is that not all resources that offer in to the BRA clear. And, the fact that uncleared summer-only resources were small, both in terms of MW quantity and a percentage of total cleared resources, demonstrates that the existing aggregation rules are working.

As further described in response to questions 3 and 5 below, to implement any contemplated alternative market designs, major changes to the input and implementation details would be necessary. Like any market rule, Market Participants need time to adapt as new rules are implemented. The most recent BRA shows that Market Participants are adapting to the

[6] *See* Tariff, Attachment DD, section 5.5A.

existing aggregation rules and have been able to substantially increase the amount of seasonal resource participation in the capacity market compared with prior years. It would be imprudent to create an alternative market design just as Market Participants are adapting to the existing rules, especially when the results from most recent BRA demonstrate that the existing aggregation rules are working.

> ***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?***

> ***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)?***

Creating a market construct tailored to further accommodate summer capacity resource participation in the capacity market would require fundamental changes to the many aspects of the Reliability Pricing Model ("RPM"). In considering the challenges associated with further accommodating summer capacity resources, it is important to remind the Commission that the numerous changes described below would be made all in the context of accommodating less than 500 MWs of uncleared summer resources based on the 2021/2022 BRA results.

One of the main issues associated with either a two-season or three-season market construct is that in accommodating such seasonal markets, there is an associated need to introduce loss-of-load expectation ("LOLE") risk into the non-summer period to reduce the level of installed capacity required during the non-summer period, as some stakeholders propose. As further explained below, while possible, such changes would have cascading impacts that fundamentally alters other aspects of the capacity market.

The PJM Installed Reserve Margin ("IRM") is the level of installed capacity that has been determined to satisfy the 1-in-10 reliability standard as measured by a total cumulative weekly LOLE equal to 0.10 days per year (i.e., the annual equivalent to the 1 event in 10 year reliability standard). In meeting this reliability standard, the value of installed capacity at the IRM level is the same for each of the 52 weeks of the annual period regardless of the level of LOLE determined for each week. In other words, the reliability value of installed capacity is no greater during weeks having non-zero LOLE risk than it is during weeks with near-zero LOLE risk. The IRM not only represents the minimum quantity of installed annual capacity needed to satisfy the peak system demands for the summer and winter periods, but also for the shoulder periods when peak demand is lower but less capacity is available due to Generator Planned Outages and Generator Maintenance Outages. In order to ensure adequate reserves under all of these conditions, the PJM IRM Study Model reflects all of these conditions (i.e. 52 weeks of peak loads and generators that are assumed to be installed for each of the 52 weeks). Due to PJM's summer-peaking load profile, LOLE naturally falls in the summer period with capacity assumed to be installed at the IRM level year-round. Thus, the distribution of loss-of-load risk across the seasons is not a predetermined "allocation" but, rather, a consequence of the PJM system monthly load profile.

The motivation for a seasonal market construct appears to be to increase the summer resource requirement and reduce the winter resource requirement. However, a two-season or three-season market construct can only be accommodated from a reliability perspective through either (1) a relaxation of the 1-in-10 standard by "accepting" some arbitrarily pre-determined additional LOLE above the 0.10 day/year total LOLE, or (2) an incremental increase in required installed capacity during the summer period. This second point would be necessary to reduce the summer-period LOLE by an amount needed to offset the additional LOLE introduced to the non-summer period while still adhering to the 1-in-10 standard by maintaining the total summation of weekly LOLE at 0.10 days per year. Both of these approaches require that LOLE risk be "forced" into the non-summer period to reduce the installed capacity required during the non-summer period. As PJM has explained previously in this proceeding, however, placing the majority of loss-of-load risk in the summer is appropriate because it is a natural result of the PJM system monthly load profile.[7]

Further, to accommodate seasonal resources that expect to receive revenues for half the year, it is unclear what value should be used for the Net Cost of New Entry ("Net CONE"), which forms the basis for demand curves. Specifically, under a two- or three-season market construct, annual resources would not be able to depend on one clearing price guaranteed for the year. As a result, should PJM allow a premium added to their offer prices? Also, there may be a need to develop a separate Net CONE value for seasonal resources to reflect seasonal costs and revenues and another Net CONE value based on annual costs and revenues. In turn, PJM would potentially need to create two separate Variable Resource Requirement ("VRR") curves, one that incorporates the higher Net CONE for seasonal resources and the current VRR curve for annual resources. Any changes to Net CONE and the VRR curve would mean that the efforts currently underway as part of PJM's quadrennial review process would need to begin anew as the current studies did not contemplate a second VRR curve or different Net CONE values to specifically accommodate seasonal resources. Moreover, the application of two VRR curves would result in separate clearing prices for seasonal and annual resources.

[7] See Comments of PJM Interconnection, L.L.C., at 4 (April 11, 2018).

Further, if separate reliability requirements are determined for different seasons by allocating the annual risk to different seasons, the allocation of costs for such resources requirements may need to be allocated by extending the summer Peak Load Contributions ("PLCs") concept to other seasons. Consequently, electric distribution companies would have to develop seasonal PLCs and PJM will have to determine Zonal RPM Scaling Factors, Zonal Capacity Prices, and Zonal CTR Credit Rates on seasonal basis for use in load settlement.

Other issues that would need to be resolved include the following:

- Would each seasonal auction be conducted and cleared independently from one another or would they be cleared simultaneously?
- If cleared simultaneously, can an annual resource submit a sell offer contingent upon only clearing in all seasons?
- Could resources submit multiple Sell Offers for the same MWs but for different seasons or combinations of seasons?

Each would require substantial efforts to set up a new market construct designed to maximize summer resource participation. And, on top of these concerns, the possibility of a unit-specific Fixed Resource Requirement ("FRR") option currently being contemplated in Docket No. EL18-178 could further complicate the aforementioned challenges. For instance, if a summer resource was removed through a unit-specific FRR, how would the proportionate amount of load be determined? Would it only be for the summer season? These are just some of the open questions and significant changes needed in the design of the capacity market to establish a two- or three-season market.

Finally, the implementation of any of these changes could result in significant market uncertainty as this would be a major departure from the current capacity market. For instance, it would be much more difficult for investors to gauge resources in which to invest and whether to invest in resources altogether. Further, the increased uncertainty may not result in any savings since market uncertainty tends to increase risk for investors, which in turn results in higher offer prices. The creation of seasonal resources that result in either a two-season or three-season market construct would create market uncertainty for not only the seasonal resources, but also the clearing prices for annual resources, which account for the vast majority of resources offered in the capacity market.

These issues, although not impossible to solve, underscore the many challenges associated with movement to a seasonal capacity construct. Given that the recent BRA results and the record to date do not justify a finding that the present capacity construct is unjust and unreasonable, continued application and monitoring of PJM's seasonal aggregation opportunities appears a more practical, at least short term approach to addressing this issue.

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.[8] 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?***

PJM performs a winter-period CETO/CETL analysis for all the regions and sub-regions included in the Regional Transmission Expansion Process ("RTEP"). PJM does not perform a summer-period CETO/CETL analysis; however it does perform an annual CETO/CETL analysis. The set of regions and sub-regions used in the winter-period CETO/CETL analysis is identical to the set of regions and sub-regions for which the annual CETO/CETL analysis is performed.

For the winter-period CETO calculations, the assumptions are identical to the assumptions in the annual CETO/CETL analysis with the exception of the following:

- Wind units are assumed to output at 33% of their nameplate capacity (instead of 13% in the annual CETO/CETL analysis based on peak summer conditions) to reflect the higher observed average output of wind units under winter peak conditions relative to summer conditions.

- Solar units are assumed to output at 5% of their nameplate capacity (instead of 38% in the annual CETO/CETL analysis based on peak summer conditions) to reflect the lower observed average output of solar units under winter peak conditions relative to summer conditions.

- The LOLE criterion for the winter peak week is 0.001 days/year. This value was established so that a negligible amount of LOLE risk in the winter is added to the 0.04 days/year resulting from the annual CETO/CETL analysis. Note that, for most of the regions and sub-regions, the LOLE risk in the annual CETO/CETL analysis is driven by loads in the summer-period.

For the winter-period CETL calculations, the assumptions are identical to the assumptions in the annual CETO/CETL analysis with the exception of the following:

- PJM load is modeled at a non-diversified forecasted 90/10 winter peak load level per the latest applicable PJM load forecast. In the annual CETO/CETL analysis, PJM load is modeled at a non-diversified forecasted 90/10 summer peak load level.

- PJM applies winter transmission facility ratings provided by each TO.

As stated earlier, the winter-period CETO/CETL analysis is performed only as part of the RTEP, whose target Delivery Year is five years in the future. Winter-period CETO/CETL analysis is not performed for a target Delivery Year three years in the future, because it is not needed for RPM purposes (in contrast, annual CETO/CETL are performed for a target Delivery Year three years in the future).[8] Therefore, results from the current winter-period CETO/CETL analysis cannot serve as inputs for alternative seasonal RPM designs.

[8] RPM is a summer-based capacity market with an annual commitment and therefore has no need for winter-period CETO/CETL values. In contrast, the purpose of RTEP is to assess the reliability of the system over the full Delivery Year, including both the summer and winter seasons. PJM therefore performs winter CETO/CETL analysis for RTEP purposes only.

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.***

The current PRD product is not a feasible path forward for incorporating seasonal DR in the capacity market because it is inconsistent with Capacity Performance. Specifically, the current PRD product effectively allows a summer resource to participate as an annual product. However, this is fundamentally incompatible with the Capacity Performance construct because the summer resources are not available for the whole year. In order words, the current PRD product enables a seasonal resource to circumvent the Capacity Performance construct and effectively be credited as an annual resource despite not being available year round.

Continuing to allow seasonal resources to participate in the current PRD program while requiring other resources to be available year round or be aggregated is likely discriminatory. Consequently, PJM is working with stakeholders to modify the current PRD product's measurement and verification provisions to bring them in line with the measurement and verification of DR under the Capacity Performance construct and will allow participation subject to such rules. Such a change is expected to be filed with the Commission in the Fall and PJM will seek an effective date prior to the 2022/2023 Base Residual Auction.

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?

Currently, curtailment events by direct load control and load management programs that are compensated in PJM's capacity market are reconstituted with metered load for purposes of PJM's load forecasting.[9] This is to avoid double-counting the load management program's capability when procuring resources for reliability purposes. In the event that curtailment events are performed by programs operating outside of PJM's markets, these are not explicilty accounted for. However, the reduced load is reflected in the metered load history. This metered load history is an input to the forecast model and will, therefore, result in a lower load forecast.

Enhanced recognition of direct load control programs operated by electric distribution companies ("EDCs") that cycle air conditioners or other appliances is currently under development in the PJM stakeholder process through the Summer Only Demand Response Senior Task Force ("SODRSTF"). The SODRSTF has progressed to the point where stakeholders are proposing solution packages that will be refined and then presented for voting.

For instance, under some of the proposals currently being developed and discussed at the SODRSTF, direct load control programs operated by EDCs will be appropriately recognized in PJM's load forecasts resulting in a reduction in the reliability requirement. Under these proposals, PJM will make load forecast adjustments that assume anticipated curtailment occurred in the past based on an amount nominated by the relevant EDC. The nominations would be based on curtailment triggers, which would require load reductions when a temperature-heat index threshold is reached, as determined by each EDC.

Currently, most proposals limit eligibility to load reduction programs governed by EDC tariffs that will meet the proposed load forecast adjustment criteria. This limitation is necessary

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[9] *See* PJM Manual 19, Attachment A.

because such EDC load programs are specified in tariffs and able to provide reasonable assurances that those programs will exist for certain periods of time and are verifiable, which helps to ensure that the load forecast does not change significantly from year to year. This eligibility requirement fulfills the goal that these out-of-market programs provide reliable and predictable load curtailments.

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?

The PJM load forecast is conducted on an unrestricted basis, meaning load is reconstituted with add-backs for load management programs that participate in PJM markets.[10] As stated previously, PJM does this to avoid double-counting these programs' benefit when procuring resources for reliability. Zones that have operated summer-focused load management programs for years have been clearing as a capacity resource and PJM reconstitutes MWs associated with the curtailment events with load as the basis for the PJM unrestricted load forecast. PJM is not aware of programs that operate outside of these instances. Current PJM load forecast accuracy results suggest that, to the extent these programs exist, they are not degrading forecast model accuracy.

Under current circumstances, the frequency of summer-focused load management programs' deployment is inconsequential to model error. The load forecast model accuracy is a

[10] *See* PJM Manual 19, Attachment A.

measure of gross load (actual metered load plus estimated load curtailments) compared with model-solved forecasted gross load (forecasted load not discounted by any load management). Zonal accuracy may vary, but not because of load management programs. If, in the future, additional load management programs operate outside of the PJM markets, the load reductions from such programs would not be explicitly accounted for in the current load forecast model and may contribute to model inaccuracy. However, PJM is currently working with PJM Members through the SODRSTF to revise the load forecast model in order to account for programs that operate outside of PJM's markets.

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.*

AEMA's complaint misconstrues a discussion between PJM and Exelon's BGE subsidiary. As PJM explained in its prior answer to the AEMA challenges,[11] the subject of PJM's discussions with BG&E was centered on load forecast rules that require load add-backs for some demand response programs to arrive at the unrestricted load to estimate what load would have been without curtailments. The rules are contained in PJM Manual 19, Attachment A, and only apply to demand response programs which are registered as "Emergency/Pre-Emergency Full (DR)," "Emergency/Pre-Emergency Capacity Only (DR)" or "Emergency Energy Only." PJM's discussion with BGE was simply to explain to BGE that should its Demand Resources exit from PJM's capacity market, then such Demand Resources would not be covered under PJM's addback rules.

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[11] *See* Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C., Docket No. EL17-36-000 (Feb. 28, 2017).

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."* [9] *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 statement referenced in this question was meant to describe how load forecasting with perfect information would be optimal. However, it is not possible to achieve this ideal situation – at least presently without further coordination between the retail jurisdictions end use customers and wholesale markets, which PJM alone cannot achieve. For instance, PJM would need to know, and be able to manage, all retail customer load reduction activity to develop a true unrestricted peak load forecast to try to estimate the impact of load reductions on forecast accuracy.

Notwithstanding, PJM has taken steps to get closer to this ideal based on load reductions that are controlled by PJM. For instance, PJM collects load drop estimates (addbacks) for load management programs (as discussed above), voltage reductions, and significant losses of load to develop unrestricted load. It may ultimately not be realistic to try to explicitly model all load reductions in the forecast instead of simply reflecting these curtailments through a lowered load history that results in a reduced load forecast.

For load management programs, add-backs are generated whenever PJM initiates a load-reduction event for committed DR, when DR conducts its annual test, or when DR implements a load reduction and receive an economic settlement through PJM. Load reductions which are not currently captured include those for customers who are registered only as Economic Load Response or who are peak shaving because PJM does not have reasonable assurances that this activity will occur in the future. Further, PJM does not know the specific peak shaving activity for the millions of customers within the PJM service territory.

Add-backs for voltage reductions can be submitted by PJM EDCs, with PJM estimating the impact for any zones which do not submit. Hourly add-backs for significant losses of load (those which go beyond the level of localized outages) are reported by the EDCs on a voluntary basis. Unreported significant losses of load typically result in outliers in the PJM load forecast model, with PJM excluding those observations from the analysis.

As noted previously, the current PJM forecast model error is relatively low and therefore PJM does not believe there is any significant model error based on existing peak shaving. This means the load forecast model is reasonably accurate by accounting for peak shaving implicitly through use of lower loads in the historical data. To the extent significant summer peak shaving exits the market or new peak shaving programs are significantly different than activity that has occurred in the past, the SODRSTF is working on proposals to incorporate this activity more responsively into the load forecast process. The proposals are focused on removing the expected future new summer only peak shaving activity from the historic load data such that this activity will be more quickly recognized in the load forecast in a timely manner.

III. CONCLUSION

Based on the record to date, including the results of the most recent auction, PJM believes that the more prudent and practical approach would be for the Commission to continue to monitor PJM's aggregation rules that are showing promise rather than attempt to re-design this aspect of the market in ways that implicate the prior Capacity Performance construct and create skewed investment signals. Although these issues can continue to be explored, PJM submits that the record does not support a finding that PJM's current aggregation rules are unjust and unreasonable as the vehicle for seasonal resources to be recognized as capacity in the PJM market.

Respectfully submitted,

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Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005

Jennifer Tribulski
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

Chenchao Lu
Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

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 Audubon, PA, this 13th day of July, 2018.

Chenchao Lu
Attorney for PJM Interconnection, L.L.C.