UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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PJM Interconnection, L.L.C.	)	Dockets Nos. ER15-623-000, -001
	)	and EL15-29

LIMITED REQUEST FOR REHEARING OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 713 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submits this limited request for rehearing of the order issued June 10, 2015 ("June 10th Order") in these proceedings.[2] In the June 10th Order, the Commission substantially approved PJM's reform of the Reliability Pricing Model ("RPM") under the Capacity Performance ("CP") proposal filed December 24, 2014 ("December CP Filing"), as modified in PJM's answer filed February 13, 2015 ("February CP Filing"), and as modified in PJM's response to the notice of deficiency, dated April 10, 2015 ("April CP Filing") (collectively, "CP Proposal").[3] The Market Monitor strongly supports the CP Proposal and recognizes the very significant contribution of the June 10th Order to the improvement of the PJM market design. The Market Monitor supports continued movement forward with implementation of the CP Proposal although the Market Monitor requests that the Commission modify its decision in a subset of specific areas based on the issues raised in

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1 18 CFR § 385.713 (2014).

2 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208.

3 PJM Filings, Dockets Nos. ER15-623-000 and EL15-29-000 (December 12, 2014).

this pleading. The Market Monitor requests that there be no delay in implementation of the June 10th Order, regardless of the Commission's response to this and other requests related to that order. The Market Monitor requests that the rules in the June 10th Order be reconsidered and that action be taken now to put in place the most fully functional market design possible and to establish durable market rules.

I. ARGUMENT

A. Parameters

The June 10th Order directed (at P 173) PJM to submit modifications to the CP Proposal to make it clear that: (i) if a capacity resource is not scheduled by PJM due to any operating parameter limitations submitted in the resource's offer, any undelivered megawatts will be counted as a performance shortfall; and (ii) if a capacity resource is not scheduled by PJM after submitting a market-based offer higher than its cost-based offer but would have been scheduled if its market-based offer had been equal to its cost-based offer, any undelivered megawatts will be counted as a performance shortfall. These findings appropriately establish the core of the capacity market design.

The capacity market is tightly linked to the energy markets. The capacity market exists only in order to permit the energy market to work by establishing a competitive market mechanism to address the shortfall in net revenues that results from the energy market design. The capacity market rules and the energy market rules must work consistently to achieve the desired incentives and efficient market results.

The following determinations create incentives in the energy market that are not consistent with the CP Proposal market design:

- The finding that it is unjust and unreasonable to cap startup and notification times for all capacity performance resources and to cap the minimum down time for capacity performance storage resources, and that resources should be able to reflect their actual startup and notification times and CP storage resources should be able to reflect their actual minimum down time.[4]

- The rejection of the CP Proposal regarding unit-specific parameter limits based on resources' physical constraints only, finding that resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[5]
- The finding that it is unjust and unreasonable to not provide uplift (make-whole) payments to resources with parameters based on non-physical constraints.[6]
- The finding that PJM submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make-whole payments.[7]

A primary goal of the capacity performance design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 10th Order's determination on non-performance charges is fully consistent with that goal. The Order's determination on parameters is not consistent with that goal.

The non-performance charges are part of the capacity market and the parameters are part of the energy market but the two are closely related because the capacity market and the energy market are fully integrated. The capacity market and the energy market, in combination with all ancillary services, determine the total price that resources receive for

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4 June 10th Order at P 436.

5 *Id* at P 437.

6 *Id* at P 439.

7 *Id* at P 440.

electric power. The designs of the capacity market and the energy market must be compatible for the market as a whole to work effectively.

By permitting generation owners to establish unit parameters based on non-physical limits, the June 10th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch. The June 10th Order (at P 433) correctly recognizes that an action by a capacity resource, whereby an inflexible parameter unreasonably increases its make whole payments and imposes higher costs on customers, is inconsistent with its obligation to make its capacity available to PJM. The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 10th Order would increase energy market uplift payments substantially. These energy market uplift costs are borne by customers, in addition to energy and capacity market payments. Uplift costs are unpredictable, opaque and unhedgeable. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The findings in the June 10th Order concerning unit parameters should be modified on rehearing. The Market Monitor suggests that the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments should reflect the flexibility goals of the capacity performance construct. These parameters can be either the OEM parameters associated with new units or they can reflect defined flexibility goals. Paying energy market uplift solely on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

B. Maximum Emergency Offers

The June 10th Order rejected PJM's proposed revisions to the Operating Agreement with regard to maximum emergency offer rules under Capacity Performance. The June 10th Order stated that the application of non-performance charges, rather than a revision of the maximum emergency offer designation rule is the appropriate method to eliminate any misuse of maximum emergency energy.[8]

Capacity that is offered as Maximum Emergency is only provided if explicitly asked by PJM when a Maximum Emergency Generation event is called. Resources are subject to non-performance charges during procedures in which PJM has not called for Maximum Emergency Energy, such as deployment of pre-emergency mandatory load management. In this situation, it is unclear whether the resources with Maximum Emergency Energy MW are exempt from non-performance charges if they were not explicitly called by PJM or if all

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8 *See* 151 FERC ¶ 61,208 at P 477.

resources with Maximum Emergency Energy should dispatch themselves up to avoid non-performance charges. Accordingly, the June 10th Order is not consistent with PJM's emergency procedures. The desirable outcome is for PJM to selectively dispatch Maximum Emergency Energy as necessary. In addition, generation owners would have an incentive and the ability to avoid clearing the Day-Ahead Energy Market by assigning a portion of their output as Maximum Emergency effectively bypassing their day ahead must offer requirement.

The findings in the June 10th Order concerning Maximum Emergency Energy should be modified on rehearing. Capacity Performance Resources should not be allowed to offer any portion of their capacity market obligation as Maximum Emergency Energy. These resources should be offered economically to PJM and PJM should commit and dispatch them according to their economic energy offers. Having the entire output of Capacity Generation Resources offered economically will lead to better pricing and reduces the amount of manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures should be allowed to offer such capacity in the Energy Market but should not take on a capacity market obligation.

C. Base Capacity – Obligations and Risk

The June 10th Order determined that it is reasonable to afford base capacity resources an opportunity to reflect capacity market compliance obligation risk in their sell offers. The June 10th Order noted that base capacity resources face enhanced performance requirements in the new market design.

The performance obligations and non-performance charges as they apply to base capacity resources do not create increased risk. Under the CP Proposal, the annual stop-loss for a base capacity resource is the resource's capacity revenues for the two Delivery Years for which there will be base resources, 2018/2019 and 2019/2020. A base capacity resource can never be required to pay back more than they received in capacity compensation. While this is a stronger incentive than included in the existing design under which a maximum of only half of the revenue has to be paid back, base capacity resources continue to have a free option under the CP design. The worst that a base resource can do is to receive zero capacity revenue in the event of very poor performance.

In contrast, the annual stop-loss for a capacity performance resource is set at 0.75 times the Net CONE for 2016/2017 Delivery Year, 0.9 times the Net CONE for the 2017/2018 Delivery Year, and 1.5 times the Net CONE from the 2018/2019 Delivery Year onwards.[9] It is possible for a capacity performance resource to pay non-performance charges that are higher than the revenue from the capacity market. This is the risk that the risk premium component is supposed to cover. Base resources do not face any risk that non-performance charges will exceed capacity market revenues.

The determination in the June 10th Order regarding the risk premium as applied to base capacity resources should be modified on rehearing.

D. Risk

PJM's December CP Filing included an additional element of ACR, defined to be "the documented and quantifiable costs of mitigating the risks associated with submission of a Capacity Resource Offer, such as insurance expenses solely attributable to the risk of being a Capacity Performance Resource."[10]

PJM's February CP Filing modified its position based on Exelon's filings to be that a seller's requested risk premium level can be "reasonably supported" rather than "documented and quantifiable."

The June 10th Order directs PJM (at P 353) to include quantifiable and reasonably-supported risks in the definition of ACR.

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9 *See* PJM proposed revised RAA § 10A(f),(h),(i).

10 *See* proposed OATT at Attachment DD, section 6.8.

The Market Monitor requests that the Commission require that the requested risk premium be documented, quantifiable and reasonably supported. It is not clear why the Commission omitted to include the modifier documented, but it is very difficult to evaluate non-documented elements of unit offers. Documentation is essential to the evaluation of all elements of offers, and the risk premium, already potentially subject to wider interpretation than other elements of offers, is no exception.

The definition in the June 10th Order regarding the definition of the risk premium should be modified on rehearing to incorporate the requirement that any risk premium be documented, quantifiable and reasonably supported.

E. Demand Response

The June 10th Order determined (at P 446) that it is satisfied that the CP Proposal would treat demand resources and other capacity resources "in a not unduly discriminatory way;" and that exempting demand resources from nodal dispatch and five-minute metering are "minor but reasonable accommodations."

These accommodations perpetuate the inefficient treatment of demand resources rather than treating them in a manner comparable to supply resources. Nodal dispatch is fundamental to the efficient operation of the wholesale power markets and five-minute metering is essential to both reliability and accountability.

The PJM rules currently provide for sub-zonal dispatch based on the zip code and zone of the demand response resource, but that dispatch can occur only if the resources in that sub-zone, which can include one or more zip codes, have been given notice at least one day before, that a sub-zone has been defined for dispatch. Such notice is not possible when unexpected events occur related to locational constraints that demand response resources could help solve. A reasonable compromise that could capture significant benefits of nodal dispatch would be to remove the notice requirement for defining a sub-zone, which does not apply to supply resources prior to nodal dispatch. For example, the elimination of the notice requirement for defining a sub-zone would have permitted PJM to use demand side resources effectively to address the unexpected reliability issue in the Erie area of the PENELEC Zone on April 21, 2015, as it occurred in real time rather than dispatching demand response resources in an entire zone, where many of the demand side resources did not contribute to a solution to the locational issue because they were not located anywhere near the critical area.[11]

Demand response resources will not provide locational dispatch in the form of sub-zonal dispatch to PJM unless the Commission orders it. It is cheaper for demand response resources to not do so. But the market rules should provide for the efficient dispatch of both demand and supply resources.

Five-minute metering would provide real-time information to dispatchers about the actual response of demand response resources and also permit the more accurate payment of the demand response resources that respond when called. Given that one of the key principles of the CP Proposal is to ensure that all capacity resources can and do perform by enforcing incentives associated with actual performance, the Commission should require five-minute metering for demand response resources to ensure that demand response resources perform under CP and play their role in markets effectively. Demand response resources are mature enough to play a role as full capacity resources without special dispensations and market efficiency requires that they do so.

This finding misses the opportunity to ensure that the CP design creates rules that help ensure that both demand resources and supply resources perform and provide a significant contribution to market efficiency.

The definition in the June 10th Order regarding the demand response resources should be modified on rehearing to eliminate the requirement for advance notice of sub-zonal dispatch and to add the requirement for five-minute metering.

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11 On April 21, 2015, PJM issued a Pre-Emergency Load Management Reduction Action in the Erie area of the PENELEC Zone to address localized post contingency voltage concerns.

F. Performance Assessment Hours

The June 10th Order accepted (at P 163) the CP Proposal's provision use of PJM's estimate of 30 Performance Assessment Hours to calculate the non-performance charge rate but directed PJM to reassess the assumed number of Performance Assessment Hours after it has gained more experience with Capacity Performance.

The estimated number of Performance Assessment Hours (PAH) is a key parameter in defining the incentive characteristics of the Capacity Performance design. Nonperformance charges vary directly with PAH.

If the number of actual PAH is less than the number of expected performance assessment hours, non-performance charges will be less than the capacity revenue received, even for a unit that never responds.

For example, if PJM declared 14 actual performance assessment hours in a year, a resource that failed to perform during all of those hours would be subject to a total non-performance charge per MW of unforced capacity of:

$$14\ actual\ PAH * [(B * NetCONE)/(30\ expected\ PAH)]$$

The equation simplifies to 0.47 * B * Net CONE. In other words, a resource that did not perform at all during any of the actual 14 PAH would pay only 47 percent of B * Net CONE rather than the appropriate level of 100 percent of B * Net CONE. If actual PAH were 30, the number of expected PAH, the non-performance charge would equal B * Net CONE.

For B equal to 0.85 and Net CONE equal to $80,530/MW-Yr, non-performance charges for a unit in BGE would be $2,281.69/MWh. Total non-performance charges would be $68,450.72/MW if the PAH were 30 hours and total non-performance charges would be $31,943.67/MW if the PAH were 14.[12] If expected and actual PAH are both equal to 14, then non-performance charges are $4,889.34/MWh.

12 PJM's proposed non-performance charge rate is based on Net CONE in $/MW of installed capacity.

The use of 30 hours is not adequately supported. The number of performance assessment hours should be based on a defined calculation method. The average of the RTO wide PAH in the last three years was 14 hours including the 30 hours in delivery year 2013-2014 that resulted primarily from January 2014. PJM asserts that 30 is a reasonable value to use as the expected number of performance assessment hours to calculate the non-performance charge rate but offers no analytical basis for using 30.

The expected number of performance assessment hours within a delivery year depends on the forecast weather conditions, forecast resource mix and units' individual availability, and the triggers used to define performance assessment hours. The divisor should be the expected value of the performance assessment hours considering appropriate triggers and using the same probabilistic model to achieve the 0.1 LOLE reliability target as used for the annual IRM study. The historical average could also be used as a proxy for the more detailed analysis.

The performance incentives are essential to the functioning of the capacity market under the CP Proposal. The calculation method of this key variable should be specified clearly so that market participants may form reasonable expectations about its future values.

The findings in the June 10th Order concerning the expected number of performance assessment hours should be modified on rehearing to use the historical three year average or to establish a clear method for determining the expected number of performance assessment hours and applying that method.

G. Peak Load Obligations

In the December CP Filing, PJM proposed to change the method for allocating the cost of capacity to zones. Under the current rules, capacity obligations are allocated to zones using a single coincident peak (1CP) method. PJM uses the ratio of the zonal coincident peak load to the Obligation Peak Load (OPL) which is the sum of the coincident, weatheradjusted, zonal summer peak loads from the preceding Delivery Year.[13] Capacity obligations are multiplied by the capacity prices to allocate capacity costs to zones.

The Electric Distribution Company (EDC) for each zone allocates the zonal capacity obligations to each end-use customer in order to define the allocation to each LSE.[14] EDCs have discretion to pick the method of allocation.[15] The allocation method results in a Peak Load Contribution (PLC) in MW assigned to each customer. The EDCs are responsible for providing the PLC information about the end use customers to the LSEs within their zone. Although each LSE's customers' aggregate behavior is the basis for what PJM will charge an LSE, LSEs determine what to bill each customer.[16]

In the December CP Filing, PJM proposed to change the allocation of capacity costs from a 1 CP method to a method using the four highest summer RTO coincident peak hours, the single highest RTO winter coincident peak hour and the highest RTO load occurring during any contiguous Performance Assessment Hours. The Market Monitor termed this the 4-1-PAH method.

In the February CP Filing, based on comments from some stakeholders, PJM requested that this change to the allocation of capacity costs be removed from consideration by the Commission.[17] The June 10th Order conditionally accepted the CP Proposal under the stipulation that PJM withdraw that change.[18]

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13 RAA Schedule 8 § A at 1.

14 *See* PJM Initial Filing, "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")." (December 12, 2014). Docket No. ER15-623-000 at 62.

15 PJM Manual 19 § 4.4, at 21.

16 PJM Manual 18 § 7.4, at 113.

17 *See* Comments and Protest of the Delaware Public Service Commission, Docket No. ER15-623-000 (January 20, 2015) at 3; Motion to Intervene and Protest of the Retail Energy Supply Association, Docket No. ER15-623-000 (January 20, 2015) at 13; Protest of Steel Producers, Docket No. ER15-623-000 (January 20,2015) at 14; Motion to Intervene and Protest of Dominion Resources Services, Inc.,

The current approach to allocating capacity obligations to zones results in a mismatch between the hours which result in the demand for a defined level of capacity, performance obligations for that capacity, and payments by loads for that capacity. PJM's December CP Proposal addressed this issue in a logical way. PJM also addressed the objections to the 4-1-PAH method. [19]

The Market Monitor continues to support PJM's proposed 4-1-PAH method.[20] The 4-1-PAH allocates the cost of capacity on the same basis that the cost of capacity is incurred and on the same basis that capacity resources are required to perform. Allocating all the costs of the Capacity Performance product based on a single summer coincident peak load is inconsistent with the CP design and provides inefficient incentives to those who use capacity.

The findings in the June 10th Order regarding the removal of the 4-1-PAH OPL calculation should be modified on rehearing to include that calculation.

ER15-623-000 (January 20,2015) at 39; Motion to Intervene of East Kentucky Power Cooperative, Inc. and Limited Protest of East Kentucky Power Cooperative, Inc. and American Electric Power Service Corporation, ER15-623-000 (January 20,2015) at 6.

18 *See* 151 FERC ¶ 61,208 (2015), Order On Proposed Tariff Revisions, Docket Nos. ER15-623-000, EL15-29-000, and ER15-623-001 (June 10, 2015) n. 27

19 *See* Answer of PJM Interconnection, L.L.C. Docket No. ER15-623-000 (February 13, 2015) at 97.

20 *See* Comments of the Independent Market Monitor for PJM, Docket Nos. ER15-623-000 and EL15-29-000 (January 20, 2015) at 13.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission grant this limited request for rehearing of the June 10th Order.

Respectfully submitted,

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Dated: July 6, 2015

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 6th day of July, 2015.

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