UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Independent Market Monitor for PJM	)	
	)	
v.	)	**Docket No. EL19-47-000**
	)	
PJM Interconnection, L.L.C.	)	

COMMENTS OF THE INDICATED PARTIES

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the "Commission"),[1] Calpine Corporation ("Calpine"),[2] Vistra Energy Corp. and Dynegy Marketing and Trade, LLC (together, "Vistra"),[3] and the Electric Power Supply Association ("ESPA")[4] (collectively, the "Indicated Parties") hereby comment on the complaint filed by the Independent Market Monitor (the "Market Monitor") for PJM Interconnection, L.L.C. ("PJM")[5] on February 21, 2019, regarding the number of Performance Assessment Intervals

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[1] 18 C.F.R. § 385.213 (2018).

[2] Calpine has separately moved to intervene in this proceeding. *See* (doc-less) Motion to Intervene of Calpine Corporation, Docket No. EL19-47-000 (filed Mar. 1, 2019).

[3] Vistra has separately moved to intervene in this proceeding. *See* (doc-less) Motion to Intervene of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, Docket No. EL19-47-000 (filed Mar. 4, 2019).

[4] Launched over 20 years ago, EPSA is the national trade association representing leading independent power producers and marketers. EPSA members provide reliable and competitively priced electricity from environmentally responsible facilities using a diverse mix of fuels and technologies. Power supplied on a competitive basis collectively accounts for 40 percent of the U.S. installed generating capacity. EPSA seeks to bring the benefits of competition to all power customers. This pleading represents the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue. EPSA has separately moved to intervene in this proceeding. *See* (doc-less) Motion to Intervene of Electric Power Supply Association, Docket No. EL19-47-000 (filed Mar. 11, 2019).

[5] Capitalized terms not otherwise defined herein have the meaning set forth in PJM's Open Access Transmission Tariff (the "Tariff").

("PAI") used in PJM's Reliability Pricing Model ("RPM") rules, including the default Market Seller Offer Cap ("MSOC").[6]

The Complaint argues that the 30 Performance Assessment Hours ("PAH"), which is equivalent to 360 PAI, that is currently used in PJM's Tariff is too high given the low number of actual PAH observed over the past few years. The Indicated Parties do not take a position on whether the Market Monitor has provided adequate evidence to show that the PAH/PAI used by PJM is unjust and unreasonable. Nonetheless, as discussed in detail in the attached affidavit of Dr. Roy J. Shanker (the "Shanker Affidavit," provided as Attachment A hereto), what is clear is that the remedy proposed in the Complaint is not just and reasonable. First, the Market Monitor's suggestion to lower the default MSOC while leaving the penalty for non-performance unchanged is inconsistent with the fundamental premise of PJM's Capacity Performance construct, which was intended to provide strong financial incentives for capacity suppliers to take actions, such as securing firm fuel or "hardening" their infrastructure, in order to maximize availability during emergency system conditions. Second, the 5 PAH recommended by the Market Monitor is too low and fails to properly reflect the possibility of system emergencies and the risks and opportunity costs that capacity suppliers assume in taking on a capacity obligation.

Accordingly, in the event that the Commission determines that some action is required in response to the Complaint, Dr. Shanker recommends that a PAH in the range of 11.5 to 17 hours, at a minimum, be used to calculate penalties for non-performance to work more harmoniously with the design of PJM's Capacity Performance construct. Dr. Shanker also recommends refining this range and selecting a final number based on the receipt of additional information from PJM, as

6 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (filed Feb. 21, 2019) (the "Complaint").

well as other potential adjustments. Dr. Shanker's approach fully addresses the concerns raised by the Market Monitor in its Complaint, but does so in a manner that increases the current penalty rate by approximately 2 to 2.5 times, which will provide stronger financial incentives for suppliers to perform during system emergencies.

I.

BACKGROUND

A. The Capacity Performance Construct And Relevant Tariff Provisions

In 2015, the Commission approved PJM's proposal to establish a new Capacity Performance Resource product "to ensure that PJM's capacity market provides adequate incentives for resource performance . . . ."[7] In support of its proposal, PJM explained that its then-existing "penalty structure is inadequate, given that it places most of the risk of resource under-performance on loads, not on resource owners or operators," and that "a seller can earn substantial revenues through PJM's capacity auctions by committing its resource as capacity, with little concern that it will lose much of that revenue even if it performs poorly."[8] Accordingly, a central tenet of the Capacity Performance proposal was the imposition of higher penalties, which the Commission recognized would "provide incentive to capacity sellers to invest in and maintain their resources by tying capacity revenues more closely with real-time delivery of energy and reserves during emergency system conditions."[9]

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7 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 at P 1 (2015) ("CP Initial Order"), *on reh'g*, 155 FERC ¶ 61,157 (2016) ("CP Rehearing Order") (together, the "CP Orders"), *aff'd sub nom. Advance Energy Mgmt. Alliance v. FERC*, 860 F.3d 656 (D.C. Cir. 2017).

8 *Id.* at P 25 (citation omitted).

9 *Id.* at P 158.

The formula for calculating penalties is set forth in Section 10A of Attachment DD to the Tariff, which states that, "[f]or each [PAI], the Office of the Interconnection shall determine whether, and the extent to which, the actual performance of each Capacity Resource and Locational UCAP has fallen short of the performance expected of such committed Capacity Resource, and the magnitude of any such shortfall . . . ."[10] A resource is assessed a Non-Performance Charge that is based on its Performance Shortfall and the Non-Performance Charge Rate (which is also referred to as the "PPR"). The Non-Performance Charge Rate, in turn, is calculated based on "an estimate of 30 hours of Emergency Actions," which reflects "the historical Emergency Action hours experienced during the 2013-14 commitment period . . . ."[11] Accordingly, the Tariff currently provides that –

> For Capacity Performance Resources and Seasonal Capacity Performance Resources, the Non-Performance Charge Rate = (Net Cost of New Entry (stated in terms of installed capacity) for the LDA and Delivery Year for which such calculation is performed * (the number of days in the Delivery Year / 30) / (the number of Real-Time Settlement Intervals in an hour).[12]

In its Capacity Performance proposal, PJM explained that the 30 hours used in the Non-Performance Charge formula is "a reasonable, forward-looking allowance for the number of hours

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10 Tariff, Attachment DD, § 10A(c).

11 CP Initial Order, 151 FERC ¶ 61,208 at P 163.

12 Tariff, Attachment DD, § 10A(e). Attachment DD to the Tariff also sets forth a "stop-loss" provision that limits Non-Performance Charges as follows:

> The Non-Performance Charges for each Capacity Performance Resource or (including locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the Delivery Year.

Id., § 10A(f).

that Emergency Actions could be in effect each year."[13] Although the Commission accepted PJM's 30 PAH estimate, it also recognized that "the [PAH] estimate affects core components of the Capacity Performance design, including the Non-Performance Charge rate and the default offer cap," and therefore required PJM to "mak[e] annual informational filings with the Commission to provide updates on the use of 30 hours for this parameter."[14]

Just as the Capacity Performance construct penalizes capacity resources for failing to perform as expected during a PAH/PAI, it also rewards resources that help maintain reliability during emergencies. Accordingly, any collected Non-Performance Charges are distributed among the resources that performed better than expected during the PAH/PAI.[15] In this respect, because an energy-only resource is not expected to perform during a PAH/PAI, its full output during an emergency would be considered over-performance that would entitle it to a performance bonus.[16]

This system of potential penalties or bonus payments also underlies the design of the default MSOC. As the Commission has explained, the default MSOC is based on the understanding that a resource "will be willing to take on a capacity obligation as long as the amount it can earn for capacity (including both capacity auction revenues as well as net Performance Bonus

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13 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"), Transmittal Letter at 43, Docket No. ER15-623-000 (filed Dec. 12, 2014). *See also id.* at 43-44 (explaining that "there were 23 such hours in the 2013/2014 Delivery Year," and that "PJM is reasonably adding some additional hours to that value to reflect the possibility that there could be a higher number of emergency hours in any given Delivery Year in the future").

14 CP Initial Order, 151 FERC ¶ 61,208 at P 163 (footnote omitted).

15 *See* Tariff, Attachment DD, § 10A(g) ("Revenues collected from assessment of Non-Performance Charges for a Performance Assessment Interval shall be distributed to each Market Participant, whether or not such Market Participant committed a Capacity Resource or Locational UCAP for a Performance Assessment Interval, that provided energy or load reductions above the levels expected for such resource during such hour.").

16 *See id.*

Payments) exceeds the amount it could earn in Performance Bonus Payments by participating in the energy market only."[17] Section 6.4(a) of Attachment DD to PJM's Tariff captures this concept by providing that the default MSOC shall be "the product of (the Net Cost of New Entry [(the "Net CONE")] applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios [(sometimes referred to as "B")] in the three consecutive calendar years (during the [PAI] in such calendar years) that precede the Base Residual Auction [("BRA")] for such Delivery Year)," where offers at or below this MSOC "shall not, in and of itself, be deemed an exercise of market power in the RPM market."[18] This provision thereby assumes that a Capacity Performance Resource shall perform at the Balancing Ratio multiplied by its committed capacity, and is foregoing potential bonus payments associated with such performance by taking on a capacity commitment. Section 6.4(a) also permits a supplier that wishes to submit an offer above the default MSOC to alternatively seek a unit-specific MSOC based on its net Avoidable Cost Rate ("ACR"),[19] where the assumption is that the unit's ACR would exceed potential bonus revenues.

B. The Complaint

The Complaint argues that the 30 PAH/360 PAI assumption that PJM included in its Capacity Performance proposal was overstated. The Complaint states that "[d]uring 2015, 2016

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17 CP Initial Order, 151 FERC ¶ 61,208 at P 336.

18 Tariff, Attachment DD, § 6.4(a). *See also id.*, § 10A (defining the Balancing Ratio as "(All Actual Generation Performance, Storage Resource Performance, Net Energy Imports and Demand Response Bonus Performance) / (All Committed Generation and Storage Capacity) . . . ."). In this way, the setting of the MSOC in PJM is similar to the Dynamic Delist Threshold in the ISO New England Inc. ("ISO-NE") Pay For Performance market, where offers up to the Dynamic Delist Threshold are allowed without review by the ISO-NE market monitor, but any potential offers above that level (Static Delist Bids) require review and approval. *See* ISO New England Inc., Transmission, Markets and Services Tariff, § III.13.1.2.3.2.1.

19 Tariff, § 6.4(a).

and 2017, there were zero emergency events that would have triggered a PAI in PJM,"[20] and that "[t]he continued level of PJM's excess reserve margins . . . reduces the likelihood of having emergency actions that could trigger PAIs."[21] In addition, the Complaint states that simulations conducted by PJM showed that "if the capacity market cleared at the target [Installed Reserve Margin ("IRM")], the expected number of PAH is 15, and if the capacity market cleared with actual observed IRM, the expected number of PAH is two."[22]

The Market Monitor proposes to use an estimate of 5 PAH, which "is based on using the two hour estimate that PJM's resource adequacy study estimated for the number of PAH with the actual, observed IRM of 21.8 percent, and adding three hours to account for the possibility of additional emergency events that might occur during the winter period."[23] At the same time, while the Complaint states that the formula underlying the default MSOC should therefore use "60 intervals (5 hours) as the estimate for H," it also proposes to "keep[] the nonperformance charge rate unchanged."[24] Effectively, this would mean that the default MSOC would be set at "one-sixth of net CONE times B . . . ."[25] The Market Monitor asks the Commission to "order PJM to revise the default MSOC based on a reasonable and supportable expectation of the number of PAI (PAH), currently five hours."[26]

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20 Complaint at 17.

21 *Id.* at 14.

22 *Id.*

23 *Id.* at 17.

24 *Id.*

25 *Id.* at 18.

26 *Id.* at 9.

On April 9, 2019, PJM filed its answer to the Complaint.[27] PJM explained, among other things, that the Commission had accepted 30 PAH as "a reasonable approximation of the upper bound of intervals that PJM's system is likely to experience Emergency Actions," and that "the Market Monitor has not sufficiently demonstrated that system conditions have drastically changed between 2015, when the Commission accepted 360 as the estimated number of [PAI], and today to justify a complete reversal of its prior decision at this time."[28] PJM also states that the Market Monitor provides no evidence of the exercise of market power, and that "the capacity market has consistently cleared below the default MSOC," thereby "support[ing] the conclusion that the existing default MSOC is not setting prices or otherwise leading to the exercise of market power as a result of some widespread use of the default MSOC value."[29] The PJM Answer further explains that the Market Monitor's 5 PAH recommendation overlooks important factors, including with respect to the General Electric Multi-Area Reliability Simulation Program ("MARS") simulations relied on in the Complaint.

The PJM Answer states that, "[i]f the Commission nevertheless is inclined to find the existing use [of] 360 as the estimated number [of PAI] is no longer just and reasonable, it must reject the Market Monitor's unjust and unreasonable proposed replacement."[30] Specifically, the PJM Answer takes issue not only with the 5 PAH proposed by the Market Monitor, but also with the Market Monitor's proposal to use different PAH/PAI for purposes of calculating the default MSOC and the Non-Performance Charge Rate, stating that "the Non-Performance Charge rate and

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27 Answer of PJM Interconnection, L.L.C., Docket No. EL19-47-000 (filed Apr. 9, 2019) (the "PJM Answer").

28 *Id.* at 5.

29 *Id.* at 6 (footnote omitted).

30 *Id.* at 15.

the expected number of [PAI] were designed to be components of the default MSOC used to estimate the competitive cost of offering a resource into an RPM Auction."[31]

The PJM Answer explains that Capacity Market Sellers are required to submit unit-specific MSOC requests by April 16, 2019, but that "Capacity Market Sellers are not currently in a position to know with any certainty whether they would be required to submit unit-specific MSOC data by the existing April 16 deadline."[32] Accordingly, in the event that the Commission requires modifications to the default MSOC in response to the Complaint, PJM requests that "any replacement rate include a sufficient timeline that allows Capacity Market Sellers to submit unit-specific MSOC data prior to the relevant RPM Auction that such replacement rate becomes effective."[33]

II.

COMMENTS

The Complaint asserts that "[t]he 30 [PAH] assumption included in the [Capacity Performance] market design was significantly overstated,"[34] which has resulted in "[a]n excessive default MSOC [that] prevents effective mitigation of market power in the PJM Capacity Market."[35] As stated previously, the Indicated Parties do not take a position on whether the Market Monitor has satisfied its burden under Section 206 of the Federal Power Act,[36] or adequately demonstrated a need for any changes to the PAH/PAI used in PJM's rules. However, in the event that the

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31 *Id.*

32 *Id.* at 20-21.

33 *Id.* at 21.

34 Complaint at 4.

35 *Id.* at 2.

36 16 U.S.C. § 824e (2012).

Commission determines that some action is required in response to the Complaint, it should not adopt the remedy proposed by the Market Monitor.

As an initial matter, although Dr. Shanker did not investigate the Market Monitor's assertions of market power,[37] he explains that the fact that "[d]uring 2015, 2016 and 2017, there were zero emergency events that would have triggered a PAI in PJM,"[38] does not mean that there has been any exercise of market power or that it is appropriate to use a PAI/PAH of zero or close to zero in calculating the default MSOC. Notably, a supplier will be submitting its offers based on its expectation of market conditions in the actual Delivery Year, which will occur three years in the future.[39] Accordingly, the fact that a PAH/PAI has not occurred in past years does not mean that such events will not occur in the future, such that there is zero risk associated with a Capacity Performance commitment or zero potential performance bonuses that will be received by energy-only resources.[40] Rational capacity suppliers will continue to conservatively plan for the occurrence of PAH/PAI, particularly given the steep penalties for non-performance under the Capacity Performance paradigm. Moreover, each supplier's offers into the RPM auctions will be informed by its own view of future market conditions, including the anticipated opportunity costs of assuming a Capacity Performance commitment, and the number of hours it believes it could have received bonus payments as an energy only resource.[41]

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37 *See* Shanker Affidavit, ¶ 27.

38 Complaint at 17.

39 The Market Monitor implicitly recognizes this by proposing to use a PAH that is based on PJM's simulation studies of future Delivery Years. *See* Complaint at 14.

40 *See* Shanker Affidavit, ¶ 22.

41 *See id.*, ¶ 15 (explaining that the MSOC should reflect "reasonable expectations of suppliers and their ability to prepare appropriate offer strategies").

In the Complaint, the Market Monitor proposes to modify the PAH input that was used to derive the default MSOC of Net CONE multiplied by the Balancing Ratio from 30 PAH to 5 PAH, with the result that the default MSOC will be reduced to one-sixth of Net CONE multiplied by the Balancing Ratio. As the Commission recognized in its orders approving the Capacity Performance construct, however, the PAH does not impact only the default MSOC. Instead, "the [PAH] estimate affects core components of the Capacity Performance design, including the Non-Performance Charge rate and the default offer cap . . . ."[42] Accordingly, it is critical that any revisions to the PAH/PAI be implemented in a way that will create the right incentives for performance and appropriately reflect the risks and opportunity costs of capacity commitments, consistent with the intent of the Capacity Performance construct. As detailed below and in the Shanker Affidavit, an approach that would be equally effective in addressing the Market Monitor's concerns, while also being more consistent with the Capacity Performance design, would be to instead increase the Non-Performance Charge Rate using a reasonable expected PAH, which Dr. Shanker estimates to range from a minimum of 11.5 to 17 hours, subject to potential adjustments based on additional data from PJM and to account for limitations in the underlying MARS model. This adjusted Non-Performance Charge Rate would also be incorporated into the default MSOC, thereby leaving the existing default MSOC formula of Net CONE multiplied by the Balancing Ratio unchanged.

A. The Complaint Erroneously Proposes To Modify The PAH Used To Calculate The MSOC While Freezing The Non-Performance Charge Rate

Although the Complaint argues that the 30 PAH currently used by PJM is too high, the Market Monitor only seeks to change the PAH used in the default MSOC calculation, while leaving

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42 CP Initial Order, 151 FERC ¶ 61,208 at P 163.

the Non-Performance Charge Rate unchanged. Dr. Shanker notes that this proposal is suboptimal and at odds with the fundamental design of the Capacity Performance construct.

As the Commission recognized in the CP Orders, a competitive offer properly incorporates expectations of expected penalties and bonus payments.[43] Accordingly, the default MSOC formula of Net CONE times the Balancing Ratio represents the "point at which low [ACR] Capacity Resources would be indifferent between taking on the obligations/risks and rewards of being a [Capacity Performance] resource versus earning bonuses from sales during performance periods while remaining as an energy only resource."[44] This formula assumed that "the Non-Performance Charge Rate . . . would be equal to the net [CONE] divided by the anticipated PAH/PAI."[45] Accordingly, "[i]f the number of expected PAH declines but the non-performance penalty stays the same, the competitive offer for low ACR resources (i.e., their opportunity cost of accepting a capacity obligation) declines proportionately, as should the MSOC."[46] Conversely, "if the number of expected PAH/PAI decreases, and the non-performance penalty rate proportionately increases, then the indifference/opportunity cost offer and the MSOC remains the same at B x Net CONE."[47]

Dr. Shanker therefore states, and has confirmed with the Market Monitor, that this means that "if the sole concern is market power mitigation, there are two plausible approaches under the [Capacity Performance] paradigm to establish the 'right' MSOC given a modification of the

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43 *See id.*; CP Rehearing Order, 155 FERC ¶ 61,157 at P 175.

44 Shanker Affidavit, ¶ 8 (footnote omitted).

45 *Id.*, ¶ 9 (footnote omitted).

46 *Id.*, ¶ 24.

47 *Id.*

expected number of PAH/PAI."[48] Specifically, the Market Monitor has proposed to incorporate a reduced PAH in the underlying MSOC formula in Section 6.4(a) of Attachment DD, thereby reducing the default MSOC to one-sixth of Net CONE multiplied by the Balancing Ratio while holding the current Non-Performance Charge Rate in Section 10A unchanged. However, as Dr. Shanker explains in more detail and as the Market Monitor has acknowledged,[49] an alternative approach would be to replace the 30 PAH that is currently used in Section 10A with a revised, lower PAH that would then be used to calculate both the Non-Performance Charge Rate and the default MSOC. Dr. Shanker states that the latter approach is "the superior option," because it "directly matches the [Capacity Performance] design by making the MSOC and the associated non-performance penalty rate consistent (i.e., the MSOC remains B x Net CONE, and the non-performance penalty rate is equal to Net CONE/Expected PAH/PAI)."[50]

While the Market Monitor's and Dr. Shanker's recommended approaches "are equivalent with respect to the function of the MSOC and determining appropriate economic offers, they are not equivalent with respect to the non-performance penalty rate and the associated operating incentives for both capacity and energy only resources."[51] Critically, the Market Monitor's proposal focuses narrowly on the offer caps rather than performance incentives, contrary to the intent of the Capacity Performance design.

As explained above, the MSOC was designed to reflect the risks and potential benefits associated with a resource taking on a capacity commitment versus remaining an energy only

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48 *Id.*, ¶ 28.

49 *See* Complaint at 6 (acknowledging that "the nonperformance charges could be recalculated based on the reasonable and supportable five PAH or 60 PAI recommended by the Market Monitor").

50 Shanker Affidavit, ¶ 29.

51 *Id.*, ¶ 30.

resource. In its CP Rehearing Order, the Commission focused on the linkage between the MSOC and the PAH, explaining –

> [T]he opportunity cost that the resource faces under PJM's Capacity Performance construct is the expected reduction in Performance Bonus Payments and/or increased Non-Performance Charges that a resource would experience by becoming a capacity resource rather than remaining a non-capacity resource. Assuming that the Performance Bonus Payment rate and the Non-Performance Charge rate (Net CONE divided by the number of Performance Assessment Hours in a delivery year) are equal, a resource's opportunity cost is therefore the product of the number of Performance Assessment Hours in a delivery year, the Balancing Ratio, and the Non-Performance Charge rate. This product equals Net CONE times the Balancing Ratio.[52]

The Market Monitor's proposal, however, assumes that there are 5 PAH for purposes of calculating the MSOC, while making no change to the Non-Performance Charge Rate, which is currently calculated using 30 PAH. This approach not only drives a wedge between the MSOC and the PAH but also undercuts the fundamental intent of the Capacity Performance construct: to create performance incentives through stringent penalties for non-performance. The Complaint fails to explain why it is just and reasonable to incorporate the revised PAH estimate only in the MSOC formula, but not the Non-Performance Charge Rate. To the contrary, as PJM explains, "[t]he Capacity Performance construct purposely uses the expected number of [PAI] in the denominator of the penalty rate to ensure that a nonperforming unit would pay the replacement rate of Net CONE if it fails to perform for all [PAI] during a Delivery Year," and the Market

[52] CP Rehearing Order, 155 FERC ¶ 61,027 at P 175 (footnote omitted). *See also id.* at P 185 (the opportunity cost of accepting a capacity obligation "is reasonably represented by the Performance Bonus Payment rate times the Balancing Ratio times the expected number of Performance Assessment Hours").

Monitor's approach "would not be consistent with this rationale, and would result in a baseless penalty rate value."[53]

If the Commission finds action to be necessary in response to the Complaint, Dr. Shanker explains that the Market Monitor's concerns regarding the MSOC "can be directly addressed under the current design by coming to an agreement as to the appropriate forecast level of PAH/PAI and using that level to calculate the MSOC and the non-performance charge rate."[54] Dr. Shanker's recommended approach allows the PAH and Non-Performance Charge Rate to "be modified based on material changes to forecasted system conditions, versus the current fixed value of 30 hours (360 PAI),"[55] thereby providing performance incentives through higher penalties and bonuses. These expectations of higher non-performance penalties and bonuses would also be carried through in the assumptions underlying the default MSOC, meaning that no change would be required to Section 6.4(a) of Attachment DD because the higher Non-Performance Charge Rate would "maintain the current B x Net CONE definition of the MSOC . . . ."[56] Dr. Shanker further states that the use of a forecast PAH "also has the advantage of making the overall [Capacity Performance] process more stable in terms of price signals to market participants for all related business decisions: entry, exit and offers."[57]

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53 *See* PJM Answer at 16 ("The use of different expected numbers of [PAI] would frustrate the underlying rationale behind the default MSOC equation as such an approach would effectively divorce the relationship between the Non-Performance Charge and the default MSOC." (citation omitted)).

54 Shanker Affidavit, ¶ 32.

55 *Id.*, ¶ 33.

56 *Id.*, ¶ 32. *See also* PJM Answer at 19 ("Retaining the same value of [PAI] in both [the Non-Performance Charge Rate and MSOC] equations is essential to maintaining the underlying logic of the existing default MSOC equation.").

57 Shanker Affidavit, ¶ 34.

Not only does the Market Monitor's suggested approach diminish the incentives for improved performance, but it would result in unit-specific mitigation of almost all resources based on their respective ACRs, which would be both burdensome and ineffective. As the Commission has recognized, "[a] default offer cap in large part serves to reduce the administrative burden on PJM, the Market Monitor, and market participants at offer prices that are clearly competitive."[58] By contrast, Dr. Shanker states that the Market Monitor's lowered default MSOC "presents a potential administrative nightmare" because it "would likely result in the application of a net ACR based MSOC to between 80-90% of generators,"[59] which would be extremely time-consuming given the almost 1,400 generators in the region.[60] Moreover, as Dr. Shanker points out, it may be very difficult to complete all necessary calculations of resource-specific MSOCs in time for the upcoming BRA for the 2022/2023 Delivery Year.[61] As PJM states, "[n]eedlessly submitting such offers for review through the unit-specific ACR process is administratively inefficient and can lead to extensive litigation that will tax the resources of the Commission and all involved parties with little to gain in terms of actual impact on the market."[62]

The Complaint suggests that the Market Monitor recommended lowering the default MSOC because recalculating the Non-Performance Charge Rate based on the Market Monitor's recommendation of 5 PAH would mean that "[t]he nonperformance charges would reach the

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58 CP Initial Order, 151 FERC ¶ 61,208 at P 345.

59 Shanker Affidavit, ¶ 35 (footnote omitted).

60 *See id.*, ¶ 36 (estimating that approximately 981 generators would be subject to unit-specific net ACR mitigation). *See also* PJM Answer at 17 ("the Market Monitor's approach would require a significant number of Market Sellers with no likelihood of exercising market power to request unit-specific ACR values simply because the intended Sell Offer prices are above the revised default MSOC value, despite the submitted offers being well below the historically competitive clearing prices").

61 Shanker Affidavit, ¶ 37.

62 PJM Answer at 17.

annual stop loss for a unit that failed to perform for just nine hours and 25 minutes."[63] Dr. Shanker therefore hypothesizes that the Market Monitor may be concerned that a higher Non-Performance Charge Rate could erode incentives for capacity suppliers to continue to perform after reaching the stop-loss limit.[64] Dr. Shanker points out, however, that any such concerns are overstated because if the Market Monitor truly expects the PAH/PAI to be very low, "then there cannot rationally also be a real worry about cumulative PAH occurring that are in excess of 150% of the forecasted level."[65] Moreover, even if this were a real concern, Dr. Shanker states that it can easily be addressed by permitting a supplier that has hit the stop loss limit to earn bonus credits by performing above the Balancing Ratio during any subsequent PAH/PAI, thereby providing an incentive for continued performance.[66] As a result, any concerns regarding capacity suppliers hitting the stop-loss limit do not justify disrupting the Capacity Performance design by adopting the Market Monitor's recommendation to lower the default MSOC while failing to adjust the PAH used in the Non-Performance Charge Rate.

B. The Market Monitor Has Proposed To Use A PAH/PAI That Is Too Low

To the extent that the Commission finds that PAH modifications are warranted in response to the Complaint, Dr. Shanker states that "the appropriate PAH should be no less than the range from 11.5 – 17 hours," which could be increased based on additional information from PJM and to account for certain factors, including the limitations of PJM's MARS simulations.[67] Dr. Shanker

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63 Complaint at 6 (citation omitted). *See also id.* at 7 (also stating that "[t]he current nonperformance charge rate would reach the annual stop loss for a unit that failed to perform for 56 hours and 15 minutes").

64 Shanker Affidavit, ¶ 57.

65 *See id.*, ¶ 58.

66 *See id.*, ¶ 59.

67 *Id.*, ¶ 40.

states that there are several factors that support this recommendation, which only captures the low end of the range of appropriate PAH.

First, Dr. Shanker points out that PJM, the entity that is responsible for maintaining reliability, has properly adopted a conservative approach in applying the results from the MARS model, because the model "assumes independent generator outages" and otherwise fails to consider factors that could result in PAH.[68] Although Dr. Shanker has not attempted to make adjustments for all of the limitations of the MARS model, his recommended range includes winter PAH,[69] because "it is reasonable to add PAH to the winter, where common mode outages related to weather have occurred, in order to address the MARS model's limitations with respect to assuming independent outages."[70]

Second, although the Market Monitor recommended a 2 PAH allowance based on the achieved reserve margin of 21.8 percent, Dr. Shanker states that this is "a very aggressive assumption given there is no guarantee of a reserve margin excess occurring or the replication of such a result in the next or any future auction," and given that historic reserve margins in the past BRAs have ranged from 16.4 percent to 23.3 percent.[71] Similarly, PJM explains that it is inappropriate to rely on the existing reserve margin because "the impending retirement of over 11,000 MWs of coal, nuclear, and other resources . . . creates a reasonable expectation that these

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68 *See id.*, ¶¶ 41-42 & n.36.

69 *See id.*, ¶ 49 (discussing addition of winter PAH).

70 *Id.*, n.40. Both the Market Monitor and PJM have also acknowledged the failure of the MARS model to properly account for winter outages. *See* Complaint at 17 (adding 3 PAH "to account for the possibility of additional emergency events that might occur during the winter period") (citation omitted)); PJM Answer at 11 ("due to its assumption of mutually independent generator forced outages, GE MARS likely underestimates the number of expected Performance Assessment Intervals during the winter periods").

71 Shanker Affidavit, ¶ 43.

retirements will likely equate to more [PAI] in the future."[72] Accordingly, Dr. Shanker recommends that "a better, but still aggressive reserve margin assumption for the PAH from the MARS analyses . . . would be to take the simple average value achieved over the 15 [past] BRAs of 19.58%"[73] Although Dr. Shanker has attempted to calculate the appropriate PAH based on this average reserve margin, he explains that a properly weighted calculation is not possible without additional information from PJM.[74]

Third, Dr. Shanker explains that the Market Monitor's estimate did not properly consider the amount of demand response in the market. In particular, because PJM treats any hour in which pre-emergency demand response is utilized as a PAH, this implies that "for each 1% additional [demand response] that displaces conventional generation, the number of PAH estimated in the PJM MARS study would increase by shifting any reference reserve margin down by a corresponding amount"[75] Dr. Shanker therefore made an adjustment to account for "the difference in total [demand response] from the most recent auction where 11,125.8 MW of [demand response] cleared versus the 8,200 assumed in the PJM simulations."[76]

Fourth, the Market Monitor does not appear to have taken transmission contingencies into account, nor is it even clear if PJM has included transmission limits in the MARS model.[77] Indeed, because the MARS model "will only show the evaluation of the level of resources versus the level

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72 PJM Answer at 14 (footnote omitted).

73 Shanker Affidavit, ¶ 43 (footnote omitted).

74 *See id.*, ¶ 46.

75 *Id.*, ¶ 48.

76 *Id.*, ¶ 49 (footnote omitted).

77 *See id.*, ¶¶ 52-54.

of demand,"[78] Dr. Shanker states that "PAH driven by events other than supply inadequacy or the use of [demand response] will not be visible."[79] Similarly, the MARS model does not appear to account for other risk factors such as gas/electric contingencies or other types of impacts.[80]

As Dr. Shanker acknowledges, his recommended 11.5 – 17 PAH only reflects adjustments to account for winter PAH and the average reserve margin in the past PJM BRAs, and to adjust for the recent increase in the amount of cleared demand response.[81] At the same time, Dr. Shanker acknowledges that some of the issues he has identified, including certain limitations of the MARS model, are difficult to quantify based on the currently public information.[82] Accordingly, Dr. Shanker states that his recommendation of 11.5 to 17 PAH reflects "a conservative range," and that this range could be increased based on additional data from PJM.[83]

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78 Dr. Shanker does recognize minimal transmission limits are included reflecting zonal constraints. *See id.*, ¶ 52.

79 *Id.*, ¶ 53.

80 *See id.*, ¶ 55; PJM Answer at 12 (explaining that the MARS simulations "do not reflect any [PAI] that could arise relating to operational risks such as under-commitments due to load forecast error in operations, potential gas pipeline disruptions, or loss of critical transmission facilities").

81 *See* Shanker Affidavit, ¶¶ 16, 40.

82 *See id.*, ¶¶ 17, 46.

83 *See id.*, ¶ 56.

III.

CONCLUSION

WHEREFORE, the Indicated Parties respectfully request that the Commission take these comments under consideration in issuing an order on the Complaint.

Respectfully submitted,

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Dated: April 15, 2019

CERTIFICATE OF SERVICE

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

Dated at Washington D.C., this 15th day of April, 2019.

/s/ Stephanie S. Lim
Stephanie S. Lim

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Independent Market Monitor for PJM	**)**	
	)	
v.	**)**	**Docket No. EL19-47-000**
	)	
PJM Interconnection, L.L.C.	**)**	

Affidavit

Of

Roy J. Shanker, Ph.D.

On Behalf of
Calpine Corporation,
Vistra Energy Corp. and Dynegy Marketing and Trade, LLC,
and the Electric Power Supply Association

April 15, 2019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Independent Market Monitor for PJM	**)**	
	)	
v.	**)**	**Docket No. EL19-47-000**
	)	
PJM Interconnection, L.L.C.	**)**	

Affidavit of Roy J. Shanker, Ph.D.

1. My name is Roy J. Shanker. My address is P. O. Box 1480, Pebble Beach, California, 93953. I am an independent consultant with my practice focused principally on the electric utility industry, Regional Transmission Organizations and associated market and business practices.

2. I have been asked by Calpine Corporation, Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, and the Electric Power Supply Association (collectively, the Indicated Parties)[1] to review and comment on the Complaint of the Independent Market Monitor (IMM) for PJM filed on February 21, 2019, in Docket No. EL19-47. The IMM's complaint addresses the question of the appropriate Performance Assessment Hours (PAH)/Performance Assessment Intervals (PAI) that should be used to establish the default Market Seller Offer Cap (MSOC) under the Capacity Performance (CP) structure of PJM's Reliability Pricing Model (RPM). This affidavit contains the results of my review.

3. I am an independent consultant. I have worked on electricity issues since approximately 1973 and independently since approximately 1981. I have had consulting related engagements related to PJM since approximately 1976. I have

[1] While I have been retained by the Indicated Parties to offer this statement, the views expressed herein represent my views alone and not necessarily the views of any of the Indicated Parties with respect to any issue.

been part of the PJM ISO/RTO stakeholder process since approximately 1995. I have participated in just about every aspect of the PJM capacity market developments since the inception of the market. I was involved in the development of the RPM through stakeholder processes and related Commission dockets and participated in the Commission settlement proceedings that resulted in the initial version of RPM.

4. I have, for over a decade, discussed issues related to the general RPM structure, including the MSOC, with most of the relevant PJM staff and management as well as the IMM. In recent years (since approximately 2015) these discussions and my related participation was done primarily in the context of the CP paradigm. I also participated in similar discussions and Commission dockets regarding the markets in ISO-NE and NYISO.

5. I have a bachelor's degree from Swarthmore College and both a master's and doctorate degree from Carnegie-Mellon University.

<u>BACKGROUND</u>

6. The genesis of the problem raised by the IMM lies in the fundamentals of PJM's capacity adequacy process. The key planning model used by PJM is PRISM. This model, among other things, assumes that forced outages of generators are random and independent.[2] The events of the polar vortex clearly demonstrated this was a bad assumption vis-à-vis actual operating requirements for Capacity Resources, with outages highly correlated (directly and indirectly) with extreme weather conditions. This mismatch of adequacy assumptions and actual performance forced an adjustment to maintain the comparability between planning assumptions and market rules in order to assure that adequacy requirements for a reliable level of capacity were being met. From its perspective, PJM faced two basic alternatives at this point; first, take physical actions and impose eligibility rules to

[2] The MARS model used by PJM that is referenced in the IMM's Complaint has the same underlying assumption of independent outages as PRISM. The implications for this on estimating the PAH/PAI are discussed below.

assure the independence of outages (e.g., require dual fuel or on site fuel storage, winterization improvements, etc.); or second, find a mechanism that would encourage/incent higher unit availability during periods of high demand and/or system stress. PJM chose the latter course in the form of the CP paradigm, implementing revisions that set materially higher penalties for failure to deliver energy during designated performance hours.

7. In adopting the CP paradigm for RPM, PJM also adopted a specific structure for the calculation of a default MSOC reflecting a competitive offer level under which resources could participate without mitigation. CP in general can be viewed as a two-settlement system for unit performance during peak periods. An obligation for such performance is sold in advance by the supplier, and in exchange for that fixed payment, the supplier faces either penalties or bonuses for actual delivered performance when needed. This system/design is driven by assumptions about the performance bonuses and non-performance penalties, the frequency of hours/intervals where performance is required, the level of performance and the avoided costs faced by a supplier vis a vis income and risk in relationship to these factors.

8. The default MSOC was intended to reflect the level of a rational competitive offer and thus it is a presumed "safe harbor" for offers, below which no mitigation applies. This was built upon the concept that within the CP paradigm, it would be possible to determine a point at which low avoided cost rate (ACR) Capacity Resources would be indifferent between taking on the obligations/risks and rewards of being a CP resource versus earning bonuses from sales during performance periods while remaining as an energy only resource.[3] Competitive

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[3] By definition, low ACR generators are those that have going-forward costs that are lower than the revenues they believe they can achieve from capacity bonus payments while being an energy only resource. Thus, low ACR resources are expected to submit offers that reflect the opportunity cost forgone by taking on a capacity obligation at a fixed price with exposure to penalties.

behavior should result in an offer at or below the indifference point for low ACR units (i.e., those units that believe they can make more from performance bonus payments than their ACR), and thus appropriately reflect the lost opportunity of assuming a competitive offer. This was established as the basis for the default MSOC and the resulting safe harbor offer cap that is in the current Tariff.[4]

9. Under the assumption that the Non-Performance Charge Rate (PPR or penalty rate) would be equal to the net cost of new entry (Net CONE) divided by the anticipated PAH/PAI,[5] the mathematics of the indifference evaluation[6] resulted in a MSOC equal to the average annual balancing ratio (B)[7] multiplied by the Net CONE.[8]

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[4] Note that while the basic theory of the CP design defined the non-performance charge rate as Net CONE divided by the PAH/PAI, Section 10A of Attachment DD actually states the current specific value as Net CONE divided by 30 hours, which was the PAH forecast proposed by PJM and accepted by the Commission at that time.

[5] PAH was changed to PAI when the PJM market rules were revised to be more consistent with five minute intervals. This was a compliance condition in Order 825. It has no substantive difference other than the PAI is 5 minutes (12 PAI per PAH).

[6] *See* IMM Complaint at pages 16 and 17 and Attachment A.

[7] The Balancing Ratio (B) is calculated during a PAH/PAI to establish each CP resource's obligation to deliver energy. The ratio is equal to the sum of actual generation performance plus storage performance plus demand response bonus output divided by the sum of committed generation plus storage capacity. The expected performance in determining whether a CP resource is eligible for a bonus payment or will be charged a penalty is based on whether the resource produces above or below its committed capacity times B. See https://www.pjm.com/~/media/committees-groups/committees/mic/20170913/20170913-item-13-offer-cap-balancing-ratio.ashx.

[8] High ACR resources are those where the expectation of their going forward costs and risk adjustment are greater than the low ACR indifference point reflected by the default MSOC (B x Net CONE). High ACR units would be expected to offer in excess of the indifference point because their net avoidable costs are greater than the expected bonus performance payments as an energy only resource. For such high ACR resources, a competitive offer level is defined by the resources' Net ACR plus a risk of penalty adjustment. The IMM Complaint principally focuses on the default MSOC, with offers from units whose ACR is greater than that level remaining subject to a resource specific review built on the unit's net ACR. However, as discussed, a direct consequence of the IMM's proposed remedy would be to materially increase the units that would be categorized as high ACR.

This MSOC is predicated on the specific relationship between the non-performance penalty rate (Net CONE/PAH) and the expected PAH.

10. Currently, the Tariff uses the original 30 PAH estimate for the purpose of calculating the non-performance charge rate. This PAH was also used in the underlying calculation of the expected low ACR unit indifference point (B x Net CONE).

11. Both PJM and the IMM agree that, empirically, the number of experienced PAH has dropped to near zero over the last several years.[9] The IMM has proposed a forecasted value of 5 PAH (60 PAI) for use in determining the MSOC based on MARS simulations conducted by PJM and the IMM's own adjustments to reflect additional performance periods in the winter.[10] PJM has interpreted the same results to support a range of 15-30 hours in the stakeholder process,[11] and PJM's answer to the IMM's Complaint states that it has concluded that the current value is appropriate.[12]

12. The specific concern raised by the IMM's complaint is that the number of experienced PAH/PAI are much lower than the level initially assumed by PJM (30 PAH/360 PAI). Thus, ***either*** the non-performance charge rate is too low (i.e., the non-performance penalty rate should be based on Net CONE divided by a much smaller number and increase), ***or*** the MSOC is too high (i.e., if the penalty rate

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[9] The results of PJM's simulations were included in Attachment B to the IMM Complaint, and in a presentation by Patrick Bruno of PJM dated August 8, 2018. See Balancing Ratio Proposals Packages A and B at 23-24, https://www.pjm.com/-/media/committees-groups/committees/mic/20180808/20180808-item-02a-balancing-ratio-proposals.ashx.

[10] IMM Complaint at 17.

[11] See id., Attachment B, Slide 17. In its presentation, PJM justified the upper bound based on a historic result:

> "Recommend using an "H" between 15 and 30 hours in denominator of the Nonperformance Charge Rate:
>
> –15 hours seen at target IRM in GE MARS Study for just summer months
>
> –30 hours seen historically (i.e. 13/14 DY even with high reserve margin)"

[12] See Answer of PJM Interconnection, L.L.C. (filed Apr. 9, 2019) (PJM Answer).

remained the same, the MSOC should be reduced by the ratio of expected PAH (e.g., 5 hours) divided by the higher original assumed value of 30 PAH, resulting in a lower MSOC).

13. The IMM's concern is that a default MSOC that is too high (or, alternatively, that there is too low a non-performance charge rate) creates the potential for the exercise of market power by suppliers with large portfolios of Capacity Resources. The IMM's concerns can be addressed by either reducing the MSOC and leaving the non-performance charge rate the same, or increasing the non-performance charge rate and leaving the MSOC the same. The IMM's complaint acknowledges these two alternative solutions, but appears to prefer, without compelling justification, the use of a lower MSOC.[13]

14. Simply adjusting the MSOC down may address the IMM's concerns regarding market power, but fails to provide the incentivizes intended by CP for a more reliable/resilient system. I believe this is an inferior choice to following the basic market design and instead increasing the non-performance penalty using a lower PAH/PAI estimate based on a properly adjusted forecast. Based on the importance of resource performance during highly correlated outage scenarios or resilience events, a properly set (higher) non-performance charge rate appears more consistent with the need to send signals to adequately value more reliable operations and necessary new investments to mitigate performance related events.

15. Adjusting the non-performance charge rate has comparable results with the IMM's proposal with respect to his concern about market mitigation, but also has the benefits of providing better performance incentives, necessitating a much lower

[13] The IMM Complaint at pages 6-7 posits that the current penalty level is appropriate and opts for a lower MSOC rather than a higher penalty rate. Admittedly, the use of a very low PAH may potentially result in an unreasonably high penalty level. However, my recommendations herein will result in a rate that is in the range of twice the current penalty, which is represents a reasonable result that is consistent with underlying CP assumptions.

administrative burden, and adding certainty to the process in terms of reasonable expectations of suppliers and their ability to prepare appropriate offer strategies. PJM has expressed the same conclusion in its answer to the Complaint.[14]

SUMMARY OF CONCLUSIONS

16. I have reached four major conclusions based on my review of the IMM's complaint.

- First, as noted in the IMM's complaint and as I have verbally confirmed in discussions with the IMM, the IMM's concerns regarding market power mitigation can be addressed by making adjustments to ***either*** the MSOC or the non-performance charge rate that are consistent with adjustments to the level of PAH/PAI.

- Second, I conclude that it is more desirable to maintain the current MSOC level based on B x Net CONE (in each LDA) and increase the non-performance charge rate by dividing Net CONE by my recommended PAH/PAI, adjusted as I discuss below. I believe this is in keeping with the original CP design proposal, as it will maintain the high penalties and associated incentives to perform. The entire CP paradigm was intended to incent behavior by higher penalties. The IMM's proposal dilutes this basic building block. My recommended approach is more consistent with the CP paradigm and is also actually very simple to implement, i.e., PJM keeps everything the same except updating the 30 PAH that is used as a divisor of Net CONE in the non-performance charge rate provision.[15] PJM previously contemplated that some adjustment to this PAH might be required as forecasted system

[14] PJM Answer at 15-16, 19-20.

[15] This adjustment to the PPR would require modification of the Tariff, Attachment DD, Section 10A(e).

conditions changed.[16] The Commission also recognized the PAH could be adjusted over time.[17]

-- The IMM's alternative fails to consistently send the competitive performance and new entry incentives associated with the higher level of penalties that were a fundamental motivation in adopting the overall CP structure. As noted, raising the non-performance charge rate is exactly equivalent to the IMM's proposal to lower the MSOC with respect to concerns regarding market power. It also appropriately maintains the current designation of a competitive offer and the associated safe harbor for offers. A related advantage is that this use of a forecasted PAH also gives greater certainty to market participants in terms of developing business strategies from new investments, maintenance policies, and the consideration of offer strategies. This approach also has a much lower administrative burden versus what historically been a drawn out process of establishing ACRs for individual generators as would be required for an estimated 80-90% of suppliers under the IMM's alternative.

- Third, I conclude that the IMM's estimate of PAH/PAI is too low. The IMM's estimate starts from a single empirical observation based on MARS simulations that were intended to estimate PAH as a function of different reserve margins. This approach of measuring PAH based on a single reserve level fails to consider the

[16] In its CP proposal, PJM explained that the non-performance charge rate would be based on "the anticipated number of Performance Assessment Hours in an average year (30)…." Response of PJM Interconnection, L.L.C. to Commission's March 31, 2015 Information Request at 1, Docket No. ER15-623-000 (filed Apr. 10, 2015) (PJM Deficiency Letter Response). PJM also stated that it "proposes 30 hours as a reasonable, forward-looking allowance for the number of hours that Emergency Actions could be in effect each year. . . . PJM could always file to change this rate divisor (up or down) if warranted by future experience." Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance AgreementAmong Load Serving Entities ("RAA")at 43-44, Docket No. ER15-623-000 (filed Dec. 12, 2014).

[17] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 at P 163 (2015) (CP Initial Order).

range of historic averages of reserve margins (and implied PAH) that have occurred since RPM was implemented.[18] It also fails to consider potential increases in demand response penetration and displacement of conventional generation, which will increase the PAH. There is also no consideration of the limitations of the MARS model. MARS is a Monte-Carlo planning model that assumes generation outages are all independent. The MARS model also fails to consider transmission related PAH, and other lower probability impacts and risks that can create PAH/PAI such as gas contingencies or common mode failures.

-- Based on the limited information available to me, I have attempted to estimate a more reasonable PAH using the PJM MARS results and recent

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[18] The table below shows the actual reserve margins in PJM's Base Residual Auctions (BRAs) to date. See PJM 2021-22 BRA auction report, Table 1, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

auction results. Taking into consideration the lower average reserve margins that have actually occurred since RPM was implemented, as well as the most recent level of cleared DR, I estimate that the appropriate PAH level for calculation of the PPR should be lower bounded in a range from approximately 11.5-17 hours.[19] I emphasize that this is a low range, because I did not have certain necessary information from PJM.[20] I also did not include adjustments for certain limitations in the MARS model, or the types of risks that PJM studies have identified regarding transmission outages, gas contingencies or other potential resiliency issues that suppliers would be expected to face.

- Fourth, I have concluded that there is a simple proposal that can mitigate any concerns regarding reduced incentives for continued performance that might occur with a higher non-performance penalty rate and the existing stop loss rules. Specifically, I propose maintaining a continuing potential upside once the stop loss limit is hit.

17. Based on the above, and if the Commission deems a change is necessary, I have the following recommendations:

a) The Commission should retain a default MSOC based on the existing B x Net CONE definition, but appropriately adjust the non-performance charge rate using my recommended PAH/PAI, adjusted as discussed below.

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[19] The MARS simulations did not show any winter PAH, but both the IMM and PJM have acknowledged that it is appropriate to include adjustments to the winter PAH to account for limitations in the model. The IMM added 1.5 winter PAH for each summer PAH. See Complaint at 17. The 17 PAH in my recommended range includes winter PAH added in a 1 to 1 ratio, which reflects my own conclusion. This 1 to 1 ratio can also be inferred from PJM's presentation. See Complaint, Attachment B, Slide 17.

[20] I could only approximate the PAH for an average reserve margin. Because PAH increase more rapidly as reserve levels fall, the correct calculation would be a higher level of PAH at the average achieved reserve margin. This calculation requires the underlying PJM data.

b) A reasonably forecasted PAH should be used. This value should be no less than a value within the 11.5 hour (138 PAI) to 17 hour (204 PAI) range. Both of these values should be increased to account for the asymmetric variance in PAH as a function of reserve margin that is discussed in more detail below. This adjustment requires the supporting data from PJM underlying the summary curve of MARS results. Other adjustments may also be appropriate to account for the limitations in the MARS model.[21]

c) To the extent necessary, I recommend an adjustment to the stop loss mechanism[22] that would allow a CP resource to potentially earn bonuses for performance above B once the stop loss limit is hit, but also would allow for continued offsetting charges to these "bonus payments" up to the stop loss limit for any further performance penalties. Additional penalties would only be charged against incremental earnings so the stop loss limit could not be exceeded.

<u>DISCUSSION</u>

There Are Two Possible Alternatives To Address The IMM's Concerns

18. As described above, the default MSOC paradigm adopted by PJM and accepted by the Commission is reasonably straightforward in terms of implementation.[23] Section 6.4(a) of Attachment DD to the Tariff describes two alternatives for determining a MSOC. First, there is the default MSOC that is based on the opportunity costs of assuming a capacity commitment that applies to what is characterized as a low ACR unit, and second, a supplier that is characterized as a high ACR unit can obtain a unit-specific MSOC based on its net ACR:

[21] PJM and its stakeholders should consider incorporating procedures for periodically reevaluating the PAH.

[22] Tariff, Attachment DD, Section 10.A(f).

[23] *See* PJM Filing, December 12, 2014, and PJM Deficiency Letter Response. *See also* IMM Complaint, Exhibit A (replicating the April 10, 2015 material). The Commission's CP Initial Order (paragraphs 314-316) also described PJM's default MSOC.

> The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below.[24]

19. The default MSOC is defined as the average Balancing Ratio (B) multiplied by the relevant Net CONE (i.e., B X Net CONE). The IMM complaint contains the generic conclusion of the competitive offer for a low ACR unit in Appendix A, equation 8 (expressed for intervals):

$$p = \left(\frac{1}{12}\right) (PPR \times H \times \bar{B}) + \ max\left\{0, \left(ACR - \left(\frac{1}{12}\right)(PPR \times H \times \bar{A})\right)\right\} \qquad (8)$$

[24] PJM Tariff, Attachment DD, § 6.4(a).

20. For a low ACR unit (a unit whose net ACR is below the anticipated level of bonus payments), the second term becomes zero. Also, where the non-performance charge rate (PPR) is defined as the Net CONE divided by the performance assessment hours (H), the first term simplifies to B x Net CONE. This simplified equation is the basis for the default MSOC in the Tariff.

21. The B x Net CONE simplification of the equation is correct when the number of PAH/PAI used for the non-performance charge rate and the expected PAH are equivalent. While the Tariff currently calculates the non-performance charge rate using 30 PAH, the default MSOC logic was based on the consistency between the PAH used and the associated non-performance charge rate (Net CONE/PAH). Logically, the PAH in the MSOC calculation should match the denominator in the PPR calculation.[25] Since the design anticipated changes to PPR based on changes to the PAH, it rightly anticipated that a change in PAH would have zero impact on MSOC when the PPR is appropriately adjusted. B x Net CONE would remain the indifference point for a low ACR unit and thus remain the appropriate offer cap when these relationships are maintained.

22. Because of a combination of high amounts of cleared supplies in the RPM capacity auctions, improved unit performance and less extreme weather, no PAHs have actually occurred recently. While historically observed PAH/PAI have been close to zero or zero for over three years, I do not believe that this is necessarily the proper focus with respect to determining a reasonable PAH. Rational offers into the BRA will be based on parties' future expectation of PAH/PAI. While historic results will inform that decision, rational offers will incorporate forward looking information regarding new entry, retirements, load forecasts, new transmission and other similar information. This perspective supports the use of an approach (not the

[25] PJM Deficiency Letter Response at 10 (stating that "[t]he proposed default capacity offer cap is a direct function of PPR" and "[t]his general offer cap equation shows that the offer cap depends directly on PPR").

specific results) taken by the IMM, i.e., to set the PAH and related penalties on reasonable forecasted results, adjusted as I discuss below.

23. To address market power concerns, the IMM has proposed to use a forecast level of PAH to reduce the MSOC, while keeping the PPR unchanged. As the IMM has pointed out, using the above equation when the hours or intervals used to define the non-performance penalty rate are higher than the actual expected PAH/PAI should result in a lower MSOC. It is simple mathematics. The IMM's complaint showed this result for an assumed use of 30 hours in calculating the PPR and 5 hours as the expected number of PAH. Because the PPR remains the same rather than being adjusted to reflect the same expected number of PAH/PAI, in this example, the calculation results in a MSOC of 1/6 x B x Net CONE:

$$p = \left(\frac{1}{12}\right)\left(\frac{Net\ CONE}{30}\right) \times 60 \times \bar{B}$$

$$p = \left(\frac{1}{6}\right) \times Net\ CONE \times \bar{B}$$

24. While there is certainly disagreement on the appropriate number of PAH/PAI (assumed to be 60 PAI (5 PAH) by the IMM and 360 (30 PAH) recommended by PJM in its reply[26]), the mathematics are straightforward and the result clear. If the number of expected PAH declines but the non-performance penalty stays the same, the competitive offer for low ACR resources (i.e., their opportunity cost of accepting a capacity obligation) declines proportionately, as should the MSOC. *Alternatively*, if the number of expected PAH/PAI decreases, and the non-performance penalty rate proportionately increases, then the indifference/opportunity cost offer and the MSOC remains the same at B x Net CONE. This occurs with the higher penalty and bonus rate capturing the same lost opportunity cost at a lower level of expected PAH. Again, my observation is this latter choice of allowing the MSOC to remain the same and increasing penalties (and

[26] PJM Answer at 10.

bonuses) is more consistent with PJM's initial motivations to create an incentive for greater reliability and availability of units during high stress periods and also encouraging new entry, as well as encouraging retirement for non-performing units.

25. In the context of the IMM's complaint, the potential market monitoring/market power implications of having either too low a performance penalty or too high an MSOC are also straightforward. Both alternatives create a gap between the correct competitive offer that should reflect the seller's indifference point and the allowed safe harbor of the "old" MSOC and its associated penalty.

26. From a market monitoring perspective, if the expected number of PAH is less than 30 and the MSOC were not adjusted down, sellers are free to make unmitigated offers in the gap between an indifference point reflecting too low a penalty rate and a higher one reflecting a penalty rate based on the lower PAH. Thus, the IMM proposes to lower the default MSOC. However, if the reality is that if the appropriate PAH is 5 hours, an equivalent action to set the "right" MSOC would be to increase the non-performance charge rate by (in this case) a factor of six to keep the indifference calculations and thus the MSOC the same at B x Net CONE. Indeed, this later approach is superior in my judgment as explained below, and is consistent with the expectation that the PAH would be periodically reviewed and that the non-performance charge rate would be adjusted accordingly.[27]

27. It is important to recognize that all the above observations only address the *potential* for the exercise of market power. While the IMM has stated its belief that parties may have exercised market power, I have not conducted any analyses of this type of behavior and have no associated conclusions.

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[27] CP Initial Order at P 163.

Instead Of Reducing The MSOC As Proposed By The IMM, The Non-Performance Penalty Rate Should Be Modified Based On Estimated PAH/PAI

28. The above makes clear that, if the sole concern is market power mitigation, there are two plausible approaches under the CP paradigm to establish the "right" MSOC given a modification of the expected number of PAH/PAI. I have confirmed this observation with the Market Monitor.[28] Given this, I believe it is very important to consider the specific properties of implementing each alternative.

29. The IMM has suggested that the MSOC be adjusted downward by freezing the non-performance penalty rate and incorporating his expected PAH/PAI forecast into the MSOC computation, which would reduce the MSOC by a factor of 6. I disagree. I believe the superior option is to proceed in a fashion that directly matches the CP design by making the MSOC and the associated non-performance penalty rate consistent (i.e., the MSOC remains B x Net CONE, and the non-performance penalty rate is equal to Net CONE/Expected PAH/PAI).

30. Several factors support this recommendation. First, while the IMM's and my approaches are equivalent with respect to the function of the MSOC and determining appropriate economic offers, they are not equivalent with respect to the non-performance penalty rate and the associated operating incentives for both capacity and energy only resources.

31. High penalties in general were an intrinsic and important part of the CP proposal and were part of the overall set of incentives presented to enhance performance under CP. While Section 10A of Attachment DD currently defines the non-performance charge rate with a 30 PAH fixed denominator, the Commission found that PJM's fixed value should be reviewed from time to time.[29] Thus, to maintain the underlying CP assumptions with respect to the PPR and the MSOC,

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[28] Telephone communications with Dr. Joseph Bowring, Independent Market Monitor, March 5, 2019, 6 PM Eastern.

[29] CP Initial Order at P 163.

penalties and bonuses should rise and fall based on changes to the reasonably forecasted PAH/PAI.

32. Increased performance incentives via high penalties and bonuses and the associated better signals regarding new entry and retirement are important elements of PJM's CP design. Consistency with this design is only maintained under my recommended alternative to maintain the current B x Net CONE definition of the MSOC and increase the non-performance charge rate (Net CONE divided by a lower forecasted PAH/PAI), versus the IMM's proposal to freeze penalties and reduce the MSOC level. The IMM believes the current PPR is sufficient to incent desired behavior, but didn't explain why this observation justifies departing from the CP underlying assumptions. The problem he has identified regarding the default MSOC can be directly addressed under the current design by coming to an agreement as to the appropriate forecast level of PAH/PAI and using that level to calculate the MSOC and the non-performance charge rate.[30]

33. Second, allowing the non-performance charge rate to increase due to a reduction in PAH/PAI is simple to implement and would require only a change to two digits in Section 10A of Attachment DD. It is basically a correct implementation of the expectation that the PAH and PPR could be modified based on material changes to forecasted system conditions, versus the current fixed value of 30 hours (360 PAI). With respect to the RPM auctions, absolutely nothing needs to be done. Incorporating the revised forecasted PAH to the default MSOC will mean that the MSOC will remain B x Net CONE. The units subject to Net ACR review will also remain the same. In fact, the only change that would occur is the change in the non-

[30] I do address one caveat below regarding an adjustment to address the potential for quickly reaching the stop loss level. However, even this concern has to be considered in the context of operating experience that has shown very few potential PAH/PAI.

performance penalty rate three years forward, when penalties would actually be assessed.[31]

34. Third, calculating the default MSOC using a reasonably forecasted PAH also has the advantage of making the overall CP process more stable in terms of price signals to market participants for all related business decisions: entry, exit and offers.

35. In contrast, the IMM proposal presents a potential administrative nightmare. I inquired of Dr. Bowring whether he could offer an estimate of the number of generators that would be subject to unit specific risk adjusted net ACR determinations under his proposed reduction of the MSOC by a factor of 6. I specifically asked he not address MWs or prices. He said that the lowered MSOC would likely result in the application of a net ACR based MSOC to between 80-90% of generators.[32]

36. There are approximately 1,379 generators in PJM.[33] Approximately 11% of PJM generation on a MW basis is excused from BRA participation, due to export sales, FRR obligations, or other reasons.[34] Assuming a roughly average size across BRA participants and excused units, this suggests that at 80%, there would be approximately 981 (1,379 x .8 x (1-.11)) generators subject to unit specific net ACR mitigation.

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[31] While I have not proposed any specific process other than correcting the IMM's 5 PAH estimate, it might be appropriate to consider an updating process for the PAH based on prospective forecasts that would be subject to review every few years. This would require more details and is likely outside of the overall scope of this proceeding.

[32] March 5, 2019 discussion with Dr. Bowring.

[33] https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.ashx.

[34] BRA Report 2021-22 BRA, Table 5, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

37. While I recognize that the IMM already has some ACR information and some units may elect default ACRs, I would still expect that it would take substantial time to negotiate this many unit-specific ACRs. Undoubtedly, there may be disagreements over both the net ACR calculation and risk adjustments, and disputes could even be filed at the Commission. Anecdotally, my experience is that these types of negotiations can take a very long time when there are differences regarding basic elements such as representation of risks. It would therefore be difficult, if not impossible, to implement this in time for the BRA for the 2022-2023 Delivery Year, which is scheduled for August 2019. Certainly, this is at minimum a multiple month process versus effectively zero implementation time for my recommendation.

Recommended Minimum PAH/PAI Values

38. The IMM recommended that a forecasted estimate of 5 PAH (60 PAI) be used in his proposed adjustment of the MSOC, down from the current 30 PAH value. Using his approach, the MSOC would be reduced to 1/6th of the current levels (based on each LDA's appropriate Net CONE value). Implicitly the IMM leaves the PPR unchanged.

39. The 5 hour PAH value is based on the IMM's review of modeling simulations conducted by PJM using the MARS reliability planning model (2 hours at the IMM's assumed reserve margin), plus an additional 3 hours reflecting potential winter outages which were not identified in the model. The Complaint states that "[t]he value of 5 hours is based on using the two hour estimate that PJM's resource adequacy study estimated for the numbers of PAH with the actual, observed IRM of 21.8 per cent, and adding three hours to account for the possibility of additional emergency events that might occur during the winter period."[35]

40. Based on my initial review of the forecast approach and assumptions, I conclude that the appropriate PAH should be no less than the range from 11.5-

[35] IMM Complaint at page 17 (citing id., Attachment B, page 16).

17 hours and could range higher based on additional evaluation of issues I have identified and review of certain data used in PJM's MARS analyses. In the following, I discuss five specific observations to support this finding. I note that my recommended 11.5-17 PAH range only accounts for certain limitations of the MARS model,[36] and the other factors discussed below would justify an even higher range.

41. First, PJM itself has taken a much more conservative view of the PAH than the IMM, recommending the use of the MARS result based on the "at IRM criteria"[37]of about 15 hours, and separately suggesting an upper value of 30 hours based on historic results (the same as the current PAH).[38] In its answer, PJM continues to recommend the status quo of 30 PAH.[39] Thus, PJM's judgment is that the status quo at twice the MARS result "at IRM criteria" is a more appropriate forward looking estimate than the IMM's use of the 21.8% case with a winter adjustment. My interpretation of comments during the stakeholder process was that PJM also considered the fact that MARS only predicted summer PAH in making its own recommendation for a result higher than the MARS "at criteria" estimate.[40]

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[36] PJM's approach was to estimate PAH based on a Monte Carlo simulation of how frequently the demand for energy over a forecast year exceeded the expected available supplies. This approach assumes independent generator outages, and reflects generation outages and variation of load, but only considers very gross transmission limits and no gas or other transmission contingencies. Part of demand was the inclusion of reserves, and part of supply reflected DR. While typically these models are used for LOLE/LOLH calculations, in this context PJM "counted" the intervals where load inclusive of reserves exceeded non-DR supply. This "counting" of PAI was consistent with the PAH/PAI triggers.

[37] The "at IRM criteria" reflects the PAH associated with a system that has capacity equal to the amount needed to maintain the target LOLE of 1 event in ten years. This is what the system is planned for. As discussed, actual reserve margins have exceeded the "at criteria" level.

[38] IMM Complaint, Attachment B, Slide 17.

[39] PJM Answer at 10-13.

[40] It is reasonable to add PAH to the winter, where common mode outages related to weather have occurred, in order to address the MARS model's limitations with respect to assuming independent outages. However, the scale of adjustment is not easily determined.

42. Since RPM was adopted 15 years ago, PJM's BRAs have cleared significantly above the IRM.[41] The PAH estimated by PJM "at IRM criteria" are higher than the actual PAH that have occurred at the actual higher reserve margins achieved in the BRAs. PJM's role as system operator and as the party ultimately responsible for reliability suggests that PJM's estimate, particularly of winter performance periods, should not be brushed aside.

43. Second, the IMM's recommended PAH value was based, in part, on the reserve margin of 21.8% that was actually achieved in the last BRA. I find this to be a very aggressive assumption given there is no guarantee of a reserve margin excess occurring or the replication of such a result in the next or any future auction. The actual reserve margin values have changed from year to year, and have ranged from a low of 16.4% for 2010-11 to a high of 23.3 in 2010-21.[42] These results reflect a continuing adjustment of supply and offer prices interacting with the downward-sloping Variable Resource Requirement Curve, as well as RPM rules and rule changes. There is no reason to believe the actual achieved reserve margins will not continue to vary in the future and impact the expected PAH accordingly. Similarly, there is no reason to assume that the reserve margin will decrease to "at criteria" IRM levels. I conclude that a better, but still aggressive reserve margin assumption for the PAH from the MARS analyses (as conducted) would be to take the simple average value achieved over the 15 BRAs of 19.58%.[43]

44. Using this adjustment alone modifies the IMM's proposed PAH of 2 hours (from the summer-only results of PJM's simulations)[44] to approximately 5 hours, or

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[41] *See* Table 1 above.

[42] *See* Table 1 above & PJM Report 2021-22 BRA, Table 1, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

[43] *Id.* (Note that there appear to be slight differences in PJM's values versus the IMM's values.)

[44] IMM Complaint, Attachment B, page 15.

a total of 8 PAH when coupled with the IMM's winter estimate. Similarly, higher winter value adjustments may be necessary to address the lack of fully independent outages. I ignored any consideration of variance in the reserve margin statistic, and as discussed below, added a winter adjustment based on the implied 1-1 adjustment in PJM's recommendation of a rate from the "at criteria" results to historic values.[45]

45. Another reason that the use of the average reserve margin in selecting the expected PAH is conservative is that this explicitly assumes that the delta/change in incremental or decremental PAH is symmetric around the average reserve margin, i.e., that you would get the same amount of change in PAH from a 1% increase or decrease in the reserve margin. This is not true. As is clearly shown by the PJM slides and the graph in IMM Exhibit B, the change is asymmetric, with a reduction in the reserve margin of 1% adding more PAH than an increase of 1% avoids. This asymmetry increases as the reserve margin gets lower. I used the simple average as it was difficult to visually estimate impacts using the PJM chart (without the formula or data points of the curve) for even a single point, let alone 15.

[45] The PJM Answer (at 11) explains as follows:

> While the results of the simulation study indicate that there may be approximately 180 Performance Assessment Intervals under the assumption that the capacity market clears at the target Installed Reserve Margin target of 15.8%, the results are conservative as used in this context in factoring that most of the reliability risk occurs in the summer months. This is because, as explained in the affidavit of Mr. Thomas A. Falin, PJM's Director of Resource Adequacy Planning, the seasonal allocation of risk is partly driven by a simplifying assumption in the GE MARS model that all generator outages are random and mutually independent. However, this is clearly not the case during extreme cold snaps as was demonstrated during the 2014 Polar Vortex in which many generating units simultaneously failed due to common causes. This indicates that, due to its assumption of mutually independent generator forced outages, GE MARS likely underestimates the number of expected Performance Assessment Intervals during the winter periods.

46. This is why I say that the impact of adding 3-6 additional PAH (summer only or with winter adjustment) related to actual reserve margins is conservative. The overall impact of moving from the IMM's 21.8% to the 19.58% average level is a reduction in reserves. This means the net adjustments of the additional data points are to a lower reserve level and higher PAH. In turn this means the calculation is including reserve level values that are farther to the left on the PAH versus the reserve level curve, where the number of PAH increases much faster per unit of decreased reserve than the portion of the curve where the IMM's estimate was taken. Further, this means that appropriate calculation of weighting each of the reserve levels by the associated PAH would result in a higher level of PAH than the PAH associated with the average reserve level. This weighted calculation is simple, but not possible without the underlying PJM data. If the Commission adopts this recommendation, I would suggest that the exact calculation be made using PJM's actual supporting data.

47. Third, the IMM's estimate fails to include or properly reflect certain properties of the MARS results, and the manner in which PJM did the specific modeling. These factors can significantly increase the estimate of PAH. For example, as modeled, PJM included 8,200 MWs of demand response (DR). However, 11,125.8 MWs of annual CP DR cleared the last BRA for 2021-22.[46] In 2015-16, prior to the implementation of CP, 14,832 MWs of DR cleared. The importance of these values is that, in the MARS models that the IMM is relying on, PJM treated DR as a supply resource, but counted the hour as a PAH if any DR that was considered pre-emergency was called upon. My understanding is that virtually all DR is considered pre-emergency.[47] The implication of this is that any increase in DR over the level modeled that displaces conventional generation *increases* the PAH (because DR is more likely to be called). This is consistent with the Emergency Procedures that

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[46] *Id.*, page 2.

[47] IMM Complaint, Attachment B, slide 14. I also confirmed this by discussion with PJM staff.

trigger Performance Assessment Hours: Pre-Emergency Mandatory Load Management Reduction.[48]

48. The implication of this is that for each 1% additional DR that displaces conventional generation, the number of PAH estimated in the PJM MARS study would increase by shifting any reference reserve margin down by a corresponding amount. For example, if there were 1% more DR (in terms of total resources), the appropriate interpretation of the results that the IMM used would be to select the PAH associated with 20.8%, not 21.8%.[49]

49. To account for this, I considered the difference in total DR from the most recent auction where 11,125.8 MW of DR cleared versus the 8,200 assumed in the PJM simulations.[50] I then used the reserve values included in the PJM 2021-22 auction results. These showed a total cleared capacity of 163,627 MW and a reserve margin of 21.5%. Adding the additional DR of 2,925.8 MW results in a shift of the reference point for the triggering of a PAH due to the use of DR by 2.2%.[51] Evaluating this shift from the average reserve margin of 19.58% discussed above (i.e., to about 17.4%) and using the same MARS results as the IMM used increases the PAH estimate for the summer to approximately 8.5 hours,[52] or a total of 11.5 PAH with the IMM's assumption of only 3 hours of winter PAH. If I account for

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[48] *Id.* See also https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-301-performance-in-reliability-pricing-model.ashx?la=en, pages 105-106.

[49] This is a simplified statement. The actual calculation would look at the 1% in MWs and recalculate the final reserve margin.

[50] It is understood that some DR may "buy out" their BRA sales, but for these purposes, I chose to maintain the cleared BRA level.

[51] *Id.* The PJM 2021-22 report has a reliability target of 134,672 MW (163,627 MW/1.215). See https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx, page 2.

[52] My PAH adjustments from the PJM summary slide are based on an approximate visual estimate of the curve intercepts. No numeric values or equations for the curve were available. These adjustments could be refined by PJM's own results.

potential additional winter hours using a 1 to 1 ratio, this would lead to the higher end of the conservative range being 17 (8.5 x 2).[53] This is the basis of my suggested range of 11.5-17 hours. This range would increase based on the reserve based weighting I suggested above.

50. This adjustment and the adjustment above regarding averaging of reserve margins are independent and therefore additive. Wherever the "right" representation of average reserve margins is, the incremental impact of additional DR penetration would still shift the reference point for calculating the PAH. However, the second "shift" would be from a lower reserve margin and again reflect the increasing slope of expected PAH.

51. I believe this is a conservative estimate of the DR impact under the current PAH "triggers." While all of the incremental DR is assumed to displace conventional generation, the amount included only reflects the most recent auction results. There appears to be a growing potential of DR to be eligible to participate in the CP paradigm, so this impact could actually increase. PJM is also considering other incentives that would allow greater participation of DR as reserves with associated increased revenues.[54]

52. Fourth, the IMM estimate has no consideration of PAH/PAI that could be triggered by transmission contingencies, other than gross limits that potentially can be included in MARS model between large transmission zones. It was not clear if PJM even included the CETL like limits in their MARS evaluation. This could be a material omission.

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[53] For the higher end, I added winter hours in a 1-1 ratio, which I inferred from PJM's recommendations (see Complaint, Attachment B, Slide 17). I eliminated the 3 hours included in the IMM's estimate of 5 hours (which implies a ratio of 1.5 winter PAH per 1 summer PAH). See Complaint at 17.

[54] In filings ER19-1486 and EL19-58, PJM proposes to increase the amount of reserve products that can be supplied by economic DR from 33-50%.

53. When considering *historic* PAH/PAI, this type of transmission impact omission is not that troubling. This is because a material transmission failure typically would result in the types of emergency triggers that PJM uses to define PAH (e.g., primary reserve warnings, load dumps, voltage reduction etc.). However, *these types of events will not appear prospectively when using a forecast model like MARS.* The model will only show the evaluation of the level of resources versus the level of demand. So, PAH driven by events other than supply inadequacy or the use of DR will not be visible.

54. Analytically, this is a difficult problem to address with the existing tools PJM has applied. In the abstract, MARS might be able to be structured with thousands of "areas" based on transmission contingencies, but this doesn't seem like a feasible or intended use of the model. In my review of the relevant literature, I was only able to identify one reference that appeared to use a full stochastic representation of both generation and transmission contingencies. This was for a reasonably sized system, but was an academic study,[55] and not representative of production software I am aware of. PJM would be best qualified to determine any further adjustments of this nature. I made no adjustment for this in estimating PAH/PAI.

55. Fifth, the IMM's evaluation and PJM's MARS studies did not include the type of additional risk factors that have recently been studied. These include issues such as gas/electric contingencies, or other extreme "resilience" type events. PJM is the only party in a position to directly make an assessment of whether or not a forecast PAH/PAI metric should be adjusted for these factors.[56] Overall, the limitations of the MARS model need to be considered and benchmarked vis a vis empirical results.

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[55] https://orsagouge.pbworks.com/f/Probabilistic+Assessment+of+Transmission+System+Reliability+Performance.pdf.

[56] See summary at: https://www.pjm.com/-/media/about-pjm/newsroom/2018-releases/20181101-pjm-completes-fuel-security-study-as-part-of-resilience-initiative.ashx, and specific PJM study at: Analyzing Fuel Supply Resilience in the PJM Region, November, 2018, https://www.pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-pjm-fuel-security-summary.ashx?la=en.

However, both PJM and the IMM agree that, at minimum, the lack of independent outages needs to be addressed by adding winter PAH.

56. Collectively all of the above support a conservative range of 11.5-17 PAH and a possible further adjustment to reflect the underlying data linked to different PAH for different reserve margins using the historic information that would increase the entire range. Some additional buffer beyond the additional winter PAH may also be appropriate to reflect MARS limitations.

Suggested Stop Loss Adjustment

57. The IMM complaint noted the significant increases that occur in penalty rates associated with the reduction in PAH/PAI.[57] Rounding my finding to an even 12 hours would result in an increase of the non-performance penalty charges of 2.5 times, or from the current range identified by the IMM of $2,684-$3,649 to $6,710-$9,112. Similarly, the stop loss value of 1.5 net CONE would increase proportionately, and be reached in approximately 18 hours. Using a mid-range value of 15 hours would double the non-performance penalty charges and hit the stop loss limit at approximately 22.5 hours. An implied concern of the IMM's discussion was whether having such a short period prior to hitting the stop loss limit would have an adverse impact on continuing efforts to perform after the limit is reached.

58. My general observation here is that the IMM can't have it both ways: if the belief is really that the PAH/PAI frequency is very low, then there cannot rationally also be a real worry about cumulative PAH occurring that are in excess of 150% of the forecasted level. At minimum, if the IMM were concerned about this issue, there should have been some consideration of this in the underlying estimate of the potential PAH/PAI, e.g. use one standard deviation below the mean of historic reserve margins under RPM. This was not suggested, and the IMM instead has

[57] IMM Complaint at page 6.

proposed an approach that would require extensive unit-by-unit ACR review of 80-90% of the market.

59. Nonetheless, if this concern remains, and my recommended approach of increasing the non-performance penalty rate based on Net CONE/PAH is used, then I would recommend a simple modification that would result in a continuing incentive for any supplier that hits the stop loss limit. There is a very simple way to do this. Once the limit is hit, the supplier should be allowed to earn bonus credits by performing above B during any subsequent PAH/PAI. This creates a continuing incentive to perform. Similarly, failure to perform above B after the limit is reached would result in penalties against any of the incremental incentives earned. This type of balanced approach retains a continuing incentive/penalty balance once the stop loss limit is reached. Good performance allows the supplier to recoup some of the assessed penalties, but any incremental failure to meet the B level of performance accrues additional penalties (but still capped at the stop loss limit).[58]

60. This concludes my affidavit.

[58] See Tariff, Section 10A(f) ("The Non-Performance Charges for each Capacity Performance Resource or (including Locational UCAP from such a resource) for a Delivery Year shall not exceed a Non-Performance Charge Limit equal to 1.5 times the Net Cost of New Entry times the megawatts of Unforced Capacity committed by such resource times the number of days in the Delivery Year.").

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Independent Market Monitor for PJM	)	
	)	
v.	)	**Docket No. EL19-47-000**
	)	
PJM Interconnection, L.L.C.	)	

Affidavit

Roy J. Shanker, Ph.D., being duly sworn, deposes and states that the statements contained in the foregoing Affidavit of Roy J. Shanker, Ph.D., are true and correct to the best of his knowledge and belief.

Roy J. Shanker

Roy J. Shanker, Ph.D.

Subscribed and sworn to before me
this 12 day of April, 2019

Fiona Vondracek

Notary Public for the State of California

FIONA VONDRACEK
Notary Public - California
Monterey County
Commission # 2237217
My Comm. Expires Apr 7, 2022

My Commission expires: 04/07/2022

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 1480 Pebble Beach, CA 93953 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W.

Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2019

249—Supreme Court of the United States. BRIEF OF ENERGY ECONOMISTS AS AMICI CURIAE IN SUPPORT OF PETITIONERS Nos. 18-868 & 18-879. Discussion of the impact of subsidies in electric energy market structures and the relationship of the instant cases where a Writ of Certiorari is being sought to previous Supreme Court precedent regarding state actions that effect Federal Energy Regulatory Commission jurisdictional rates.

2018

248—On behalf of PJM Power Providers (P3). Federal Energy Regulatory Commission. Docket EL18-178. Affidavit addressing the appropriate mechanisms to address state/public policy subsidies in the PJM Reliability Planning Model capacity construct. Related comments with respect to a "Clean" Minimum Price Offer Rule.

247—On behalf of Calpine Corporation, Eastern Generating and CPV Power Holdings. Federal Energy Regulatory Commission. Docket No. EL18-169. Affidavit addressing the the establishment of a "clean" Minimum Offer Price Rule for capacity offers in the PJM markets.

246—On behalf of DC Energy LLC and Vitol Inc. Federal Energy Regulatory Commission. Docket No. ER18-1334. Affidavit on the CAISO proposals to limit source and sink pairs in its annual and monthly CRR auctions, as well as comments addressing appropriate coordination of transmission outage and constraint information.

245—On behalf of the PJM Power Providers. Federal Energy Regulatory Commission Docket No. ER18-1314-000. Affidavit on the PJM proposed mitigation alternatives for addressing out of market subsidies either by Repricing or a modified Minimum Offer Price Rule.

244—On behalf of Joint Commentors. Federal Energy Regulatory Commission Docket EL18-34. Participation in the preparation of comments addressing PJM's proposed fast start pricing modifications and related price formation issues.

243—On behalf of the PJM Power Providers Group. Federal Energy Regulatory Commission Dockets EL17-32 and EL17-36. Pre-Technical Conference Comments and participant technical conference regarding seasonal capacity products and specific related reliability and forecasting questions from Commission Staff.

2017

242—On behalf of the PSEG Companies. Federal Energy Regulatory Commission Docket No. ER13-535-000. Affidavit regarding implementation of Court of Appeals remand to FERC of the PJM capacity market Minimum Offer Price Rule.

241-- In the United States Court of Appeals for the Second Circuit. Case No. 17-2654.Co-writer/sponsor of the Brief of Energy Economists as Amici Cucriae in Support of Plaintiffs-Appealants-Reversal. Comments regarding the impacts of subsidies on the operation of organized electric markets.

240—In the United States Court of Appeals for the Seventh Circuit. No. 17-2433.Co-writer/sponsor of the Brief of Energy Economists as Amici Cucriae in Support of Plaintiffs-Appealants. Comments regarding the impacts of subsidies on the operation of organized electric markets.

239—Invited speaker Federal Energy Regulatory Commission technical session, Docket AD17-11. Comments on the appropriate incorporation of state policies in wholesale electric markets. Submission of post technical session comments.

238—On behalf of PJM Power Providers. Federal Energy Regulatory Commission Dockets EL17-36 and EL17-32 addressing the current Capacity Performance design and criticisms related to the exclusion of an inferior seasonal capacity product. Explanation of how PJM establishes its adequacy targets and whether or not the asserted criticisms were valid.

2016

237- On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Submission of post technical session statement regarding PJM FTR market "netting" proposal.

236-On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Participant in two Technical Session Panels addressing PJM FTR market design and deficiency in the pending proposal to remove netting in the market settlement.

2015

235- On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Affidavit regarding MISO capacity market design and also addressing use of opportunity costs in offers.

234-On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Discussant in technical session addressing the establishment of opportunity costs as the basis for capacity reference pricing in the MISO Planning Resource Auctions.

233-On behalf of Dominion Virginia Power. Federal Energy Regulatory Commission Docket ER15-1966. Affidavit regarding changing economic incentives for suppliers associated with the modification of PJM's calculation of Lost Opportunity Costs.

232-On behalf of "Indicated Suppliers" Federal Energy Regulatory Commission Docket No. EL15-64-000. Testimony addressing the appropriateness of proposed changes to the NYISO buyer side mitigation exemptions.

231-On behalf of Hydro Quebec, Energy Services U.S. Federal Energy Regulatory Commission Docket No. ER15-623. Affidavit addressing the consistent treatment of energy imports under PJM's Capacity Performance proposal.

230-Before the Supreme Court of the United States, No. 14-995, On Petition for a Writ of Certiorari to the United States Court of Appeals for the Third Circuit. Brief of electrical engineers, scientists and economists as amici curiae in support of petitioners. Metropolitan Edison et al. versus Pennsylvania Public Utility Commission et al., http://www.americanbar.org/content/dam/aba/publications/supreme_court_preview/briefs_2015_2016/14-840_Borlick_et_al.pdf.

2014

229-On behalf of Benton County Wind Farm. United States District Court Southern District of Indiana, Indianapolis Division, Civil Action No. 1:13-cv-1984-SEB-TAB. Expert Reports addressing custom and practice in electric power purchase agreements.

228-On behalf of FirstEnergy Services. FERC Docket EL14-55. Affidavit related to the appropriate characterization of Demand Response in Capacity Markets reflecting performance as the reduction of retail energy consumption.

227-Federal Energy Regulatory Commission. Docket RM10-17. On my own behalf, a statement regarding the ability of the PJM capacity and energy markets to clear in the transition from any determination that demand response would be excluded jurisdictionally from wholesale markets. This could in turn result in a more appropriate representation of retail demand response.

226-Illinois Commerce Commission. Matter: No. 13-0657. On behalf of Commonwealth Edison Company. Testimony regarding the operation of the PJM regional transmission expansion planning process in general and particularly with regards to the preservation of long-term transmission rights (Stage 1A Auction Revenue Rights), and the consequences that occur when such mandated rights are infeasible.

225-Federal Energy Regulatory Commission. Docket ER14-1579. On behalf of H-P Energy. Affidavit explaining importance of property rights and associated contracts within the PJM transmission planning process, particularly as they pertain to Upgrade Construction Service Agreements.

2013

224-Federal Energy Regulatory Commission. Docket No. ER14-456. On behalf of NextEra Energy to analyze a proposed modification to the PJM Tariff allowing for "easily resolved constraints" to be address by transmission upgrades without any analyses of benefits.

223-Federal Energy Regulatory Commission. Docket No. ER14-504. Affidavit on behalf of PJM Power Producers addressing the interaction between the PJM adequacy planning processes and the formulation of saturation constraints on Limited and Extended Summer Demand Response products.

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

2011

211-Federal Energy Regulatory Commission Docket No. ER12-513-000. On behalf of PJM Power Providers, testimony regarding the establishment of system wide values for the net cost of new entry related to modifications of the Reliability Planning Model.

210-Federal Energy Regulatory Commission Docket No. EL11-56-000, on behalf of First Energy Services. Affidavit regarding the appropriateness of proposed transmission cost allocation of Multi-Value Projects to an exiting member of the Midwest Independent System Operator.

209-Federal Energy Regulatory Commission Docket No. ER11-4081-000, on behalf of "Capacity Suppliers". Affidavit addressing correct market design elements for Midwest Independent System Operator proposed resource adequacy market.

208-Public Utility Commission of Ohio, Case Nos. 11-346-EL-SSO,11-348-EL-SSO,Nos. 11-349-EL-AAM, 11-350-EL-AAM, on behalf of First Energy Services. Testimony regarding the interaction between the capacity default rates for retail access under the PJM Fixed Resource Requirement and the PJM Reliability Planning Model valuations.

207-Federal Energy Regulatory Commission Dockets No. ER11-2875, EL11-20, Staff Technical Conference on behalf of PJM Power Providers, addressing self supply and the Fixed Resource Requirement elements of PJM's capacity market design.

206-New Jersey Board of Public Utilities, Docket Number EO11050309 on behalf of PSEG Companies. Affidavit addressing the implications of markets and market design elements, and regulatory actions on the relative risk and trade-offs between capital versus energy intensive generation investments.

205-Federal Energy Regulatory Commission Docket No. ER11-2875. Affidavit and supplemental statement on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry and recommendations for tariff revisions.

204-Federal Energy Regulatory Commission Docket No. EL11-20. Affidavit on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry.

203-Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

202-New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381.

201-Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

200-Federal Energy Regulatory Commission. Docket ER11-2059 Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

199-Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

198-Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the

New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

197-Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

196-Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

195-Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

194-PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

193-Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

192-Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

191-Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

190-Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

189-American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

188-Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

187-Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

186-American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

185-Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

184-Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

183-Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

182-Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

181-Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

180-Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

179-Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

178-Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

177-FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

176-FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

175-FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

174-FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

173-United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

172-FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

171-FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

170-FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

169-FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

168-FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

167-FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

166-FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

165-American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

164-Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

163-Federal Energy Regulatory Commission Docket No. EL03-236-003. Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

162-Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

161-Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

160-Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

159-Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

158-Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

157-Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

156-Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

155-Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

154-Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

153-American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cinergy Solutions regarding an energy services agreement related to a cogeneration facility.

152-Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

151-Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

150-Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

149-Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

148-Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

147-Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

146-Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

145-Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

144-Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

143-Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

142-United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

141-Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

140-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

139-Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

138-Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

137-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

136-Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

135-Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

134-Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

133-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

132-Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

131-Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

130-Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

129-United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

128-Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

127-New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

126-Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

125-American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

124-Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

123-Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

122-Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

121-Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

120-Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

119-New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

118-JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

117-Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

116-Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

115-Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

114-Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

113-U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

112-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

111-Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

110-United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

109-United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

108-Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

107-Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New

York Power Pool and the implementation of locational marginal cost pricing.

106-Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

105-Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

104-American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

103-Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

102-New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

101-Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

100-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

99-Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

98-New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

97-State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

96-United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

95-United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

94-American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

93-Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

92-Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

91-New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

90-Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

89-Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

88-American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

87-United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

86-Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

85-Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

84-New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

83-Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

82-New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

81-New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

80-American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

79-U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

78-State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

77-Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

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74-Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

73-State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

72-State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

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70-Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

69-Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

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68-Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

67-Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

66-State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

65-State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

64-State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

63-Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

62-Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

61-Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

60-Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

59-State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

58-District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

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56-State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

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54-State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

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52-Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

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1989

49-Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

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43-Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

42-Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

41-Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

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39-Florida Public Service Commission. Docket No.8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

38-Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

37-Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factorapplication and relationship to avoided costs.

36-District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

35-Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

34-Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

33-Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

32-Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

31-Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

30-U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

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27-Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

26-Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

25-Bonneville Power Administration. Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

24-Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

23-Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

22-Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

21-Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

20-Connecticut Light and Power. Docket No. 85-08-08. Assist in the development of testimony for industrial natural gas transportation rates.

19-Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

18-Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

17-Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

16-Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

15-New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

14-Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

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13-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-serviceprocedures, class rate of return and rate design.

12-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

11-Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

10-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

9-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

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8-Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

7-Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

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5-Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

4-Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

3-PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

2-PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

1-Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia
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