UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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PJM Interconnection, L.L.C.	)	Docket Nos. EL19-58-000,
	)	ER19-1486-000
	)	

ANSWER AND MOTION FOR LEAVE TO ANSWER OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rules 212 and 213 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits this answer to the answers/replies submitted in this proceeding by PJM on June 21, 2019 ("PJM Answer");[3] Exelon Corporation ("Exelon") on June 19, 2019;[4] the Electric Power Supply Association on June 26, 2019("EPSA"), PJM Power Providers Group on June 20, 2019 ("Power Providers"); PSEG Companies on June 20, 2019 ("PSEG"); Vistra Energy Corp. and Dynegy Marketing and Trade, LLC on June 20, 2019 ("Vistra/Dynegy"); and Calpine Corporation and LS Power Associates, L.P., on June 24, 2019 ("Calpine/LS Power").

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1 18 CFR §§ 385.212 & 385.213 (2018).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

3 Including Attachment A, Reply Affidavit of Drs. William W. Hogan and Susan L. Pope ("Hogan and Pope"); Attachment B, Reply Affidavit of Adam Keech ("Keech"); Attachment C, Affidavit of Dr. Patricio Rocha Garrido ("Rocha Garrido"); and Attachment D, Reply Affidavit of Chris Pilong ("Pilong").

4 Including Attachment, Affidavit of Michael M. Schnitzer ("Schnitzer").

PJM's ORDC filing proposes dramatic changes to the energy market, the capacity market and the reserve market while asserting that the changes affect only the reserve market. PJM's impact on the energy market is significantly larger than the impact on the reserve market. PJM's proposal would guarantee double recovery for generation owners by ignoring the symbiotic relationship between the energy and capacity markets. PJM has failed to identify an issue or issues that require the dramatic changes PJM proposes. Many of the rationales now advanced by PJM were never raised by PJM in the stakeholder process. PJM has failed to explain how PJM's proposed changes would enhance or even maintain the competitiveness of the markets. It would be unjust and unreasonable to make the dramatic changes that PJM is proposing because PJM has not identified the issues that need the proposed solution, because PJM has not supported the detailed changes it proposes, because PJM has requested that the impacts on the energy and capacity markets be ignored, and because the proposed changes would create significant unintended consequences that PJM cannot foresee or address.

The Market Monitor, together with the majority of stakeholders, supports a step by step approach to identifying and solving the market design issues identified in the stakeholder process that preceded PJM's filing of the March 29th Complaint.[5] [6] The combination of the tier 1 and tier 2 synchronized reserve markets is such a step. The increase of the maximum penalty price from $850 per MWh to $1,000, and to $2,000 when there are approved cost-based offers at that level, is such a step. Shifting the ORDC based on defined operator actions is such a step. PJM asserts that all of PJM's proposed changes need to be made at once, that PJM's changes are simple and that all the other RTO/ISOs have made the same changes. PJM's assertions are demonstrably incorrect.

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[5] PJM Minutes, Markets and Reliability Committee (January 24, 2019) at 2, <*https://pjm.com/-/media/committees-groups/committees/mrc/20190221/20190221-consent-agenda-draft-minutes-mrc-20190124.ashx*>, accessed May 15, 2019.

[6] PJM Filing, Docket Nos. EL19-58-000, et al. (March 29, 2019) ("March 29th Complaint").

The March 29th Complaint should be rejected, but, if the PJM market rules are found not just and reasonable, only the significant but moderate steps proposed by the Market Monitor should be approved and PJM's misguided proposals should be rejected. These are complex issues which affect all parts of PJM markets. Changes to the markets should be undertaken in steps, evaluated and then additional steps taken but only if necessary in order to achieve the goal of sustainable competitive markets.

PJM attempts to downplay the significance of PJM's proposed changes. PJM asserts that the $2 billion increase in costs to customers is really only $0.5 billion, if looked at the right way. PJM has also failed to calculate the combined impact of the PJM proposals and the implementation of the Commission's recent fast start order. PJM calculated the separate impact of the fast start order as $1 billion. PJM ignores the $9.2 billion in double payment of revenues in the energy and capacity markets that would directly result from PJM's proposal. PJM's proposals will have unknown and unintended consequences for PJM markets and PJM participants. PJM, in developing some of the actual details of its proposals has also uncovered new issues itself, or caused the Market Monitor and others to discover new issues, that need to be addressed prior to implementing PJM's proposed approach. PJM has asked for a delay in implementing the fast start pricing order as a result of complications that PJM did not anticipate.[7] The fast start implementation complications are only a precursor to and a warning of the unforeseen complications that would result from an attempt to implement the proposals included in PJM's March 29th Complaint.

[7] Motion of PJM Interconnection, L.L.C. for Extension of Time and Request for Shortened Answer Period, Docket No. EL18-34-000 (July 5, 2019).

I. ANSWER

A. PJM Fails to Establish That Any PJM Market Rules Are Unjust and Unreasonable.

1. Scarcity Pricing Is an Element of Energy Market Pricing, and PJM Has Not Established That Energy Market Pricing Is Unjust and Unreasonable.

It is well understood that scarcity pricing is, first and foremost, an element of energy market design. PJM implemented scarcity pricing in response to Order No. 719, which explicitly required scarcity pricing as a payment to energy resources, particularly demand response, to elicit more energy on the system at times of reserve shortage. The Commission described its goals in Order No. 719:

> Therefore, we are taking action to remove such barriers to demand response by requiring price formation during periods of operating shortage to more accurately reflect the value of such energy during such shortage periods. Each RTO or ISO is required to reform or demonstrate the adequacy of its existing market rules to ensure that the market price for energy reflects the value of energy during an operating reserve shortage.[8]

PJM claims that the consistent use of a cooptimization algorithm in its joint dispatch and pricing of the energy and reserve markets implies that its proposal does not alter the energy market, and therefore, the March 29th Complaint does not require an assertion that energy market pricing is unjust and unreasonable.[9] This argument attempts to hide the realities of the market behind the mathematics. As Witnesses Hogan and Pope reiterate (at 6–7), PJM proposes to alter LMP by moving from shortage pricing to pervasive scarcity pricing. Witnesses Hogan and Pope clarify that shortage pricing is not enough and that full scarcity pricing, including higher energy pricing, is required.

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8 *Wholesale Competition in Regions with Organized Electricity Markets*, Order No. 719, 125 FERC ¶ 61,071 at P 194 (Oct. 17, 2008).

9 PJM Answer at 25, citing the March 29th Complaint.

As stated in Order No. 719, scarcity pricing, specifically shortage pricing, was implemented to reflect the value of energy in the energy market price under the condition of a reserve shortage. A change to scarcity pricing requires a finding that the energy market price, LMP, is unjust and unreasonable. Despite PJM's arguments, the prior addition of the small 190 MW step to the ORDC is not a precedent for the Commission approving the March 29th Complaint's extended sloping ORDC.[10] The 190 MW step does not create pervasive scarcity pricing but instead was explicitly designed to moderate shortage pricing.[11] Pervasive scarcity pricing in the absence of reserve shortages, as proposed by PJM, is a deviation from the policies set forth in Order No. 719 and implicates the formation of LMP in all RTOs and ISOs.

2. The Practice of IT SCED Bias Does Not Indicate an Unjust and Unreasonable Market.

a. IT SCED Bias Will Continue Under PJM's Proposal

PJM has not indicated that IT SCED load biasing will end if the proposed ORDC is implemented. Even with PJM's ORDC, PJM's operators will continue to exercise discretion through load biasing but that discretion will have amplified impacts on energy prices. This makes clear that PJM is not addressing the underlying issue. More transparency about the nature and consequences of operator actions is required before major market changes are made. PJM has not done any actual analysis to link IT SCED bias to actual commitment to RT SCED and to actual market results. The Market Monitor has started a stakeholder process to improve transparency and to improve the analysis of these interactions in order to understand the actual dynamics. [12] While the stakeholder process is starting with the

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10 PJM Answer at 19.

11 *See* Keech.

12 PJM, MIC, Issue Charge/ Problem Statement—Five Minute Dispatch and Pricing (June 12, 2019) <https://www.pjm.com/-/media/committees-groups/committees/mic/20190612/20190612-item-02a-five-minute-pricing-issue-charge-rev2-clean.ashx> and MIC Minutes (July 10, 2019).

relationship between RT SCED and LPC, it would be a natural evolution to consider the definition, role and purpose of operator load bias in IT SCED and RT SCED.

It is also essential to distinguish between load bias and out of market commitments. The Market Monitor has made it clear that operator decisions intended to increase reserves through out of market actions should be reflected in shifts of the ORDC and the associated change in reserve prices.

b. IT SCED Bias Was Not the Determinant of Low Reserve Prices During PJM's 2019 Winter Peak.

Exelon asserts (at 8) that PJM took "discriminatory actions to create 'pseudo-reserves'" on January 30 and 31, 2019. PJM's Pilong provides a table (at 3) representing that the system would have experienced synchronized reserve shortage in 44.4 percent of market intervals but for IT SCED bias. Neither is correct. Both are misleading. Witness Pilong admits (at 13) that the analysis does not represent what actually happened, but shows a "worst-case scenario that assumes operators took action based on the recommendations of the biased IT SCED case." The assumption is invalid. Operators did not take action on the majority of the biased IT SCED recommendations. In general, operators do not take actions on the majority of commitments recommended by biased IT SCED cases. Witness Pilong's statement corroborates the Market Monitor's analysis of the events and of the general role of IT SCED recommendations. IT SCED bias is a tool used by dispatchers to provide information to the dispatchers. It is a form of sensitivity analysis. PJM has not claimed and could not support the claim that IT SCED bias is used to create reserves. There is a difference between a bias that reflects operator expectations about load and a bias that is designed to increase reserves. If the operators use bias to increase reserves, those actions should be transparent and should result in shifting the ORDC, as recommended by the Market Monitor.

During the hour in which PJM biased the IT SCED load the most, 3,000 MW on average on January 31, 2019, HE 0600, the market results do not support PJM's assumptions and conclusion. On average, in that hour, IT SCED recommended the commitment of 2,562 MW. In the same hour, only 932 MW were committed by PJM in the hour, 793 MW were self-committed in the hour, and 116 MW had no commitment reason.[13] The data do not support the claim that even the largest IT SCED load bias resulted in a correspondingly large resource commitment and the creation of excess reserves.

It is obvious that when PJM dispatchers bias the IT SCED load, IT SCED recommends the commitment of additional resources, if the resources that are already online cannot meet the additional demand. But most of the IT SCED recommendations do not result in actual commitments. The bias in the IT SCED advisory market tool has no direct or demonstrable impact on the real-time energy and reserve markets. PJM has not quantified the actual impacts of IT SCED bias on the market or on reserve levels. PJM has not shown that IT SCED bias led to price suppressing commitments on January 30 or 31, 2019. PJM has not shown that its dispatchers take regular systematic actions that increase reserves beyond the requirement. PJM has not shown that IT SCED biasing practices render the current ORDC unjust and unreasonable. PJM did not raise the IT SCED load bias issue during the Energy Price Formation Senior Task Force (EPFSTF) stakeholder process. This is surprising if the role of load biasing in IT SCED is as critical as now alleged.

3. Reserve Prices Equal to Zero Are Not an Unjust and Unreasonable Outcome.

In making its claims that reserves have value according to a downward sloping demand curve, PJM assumes that operators make decisions based on economics, i.e. about whether additional reserves are worth the cost. This assumption is not consistent with observed market outcomes. There is no evidence to support PJM's assertion. PJM has not described its operators as making decisions based on economic criteria rather than decisions based on reliability criteria. Operators procure additional reserves when they deem them necessary for reliability. When that is the case, the operators see the reserves as

13 PJM does not record the reasons that dispatchers follow or do not follow IT SCED recommendations but the commitment reasons are logged as part of PJM's Dispatch Management Tool (DMT).

valuable. If the amount of reserves deemed necessary (valued) by the operators can be fully supplied by the market at a cost of zero, the efficient price is zero. If meeting the operator valued quantity of reserves is costly, the efficient price is the marginal cost of providing the reserves. Reserves are a reliability product, and an inelastic demand curve is appropriate. No amount of historic forecast error data tells PJM the date and times when the operators will value additional reserves or exactly what quantity the operators will value when those times arise. The current vertical ORDC with extended reserve requirements under limited and defined circumstances is just and reasonable, and consistent with the value of reserves. The current reserve pricing mechanism is consistent with the value of reserves.

Imposing an extended sloping ORDC on the market to create a price for reserves at times when operators have not explicitly deemed them necessary is not consistent with the value of reserves. There is no value to reserves beyond the amount deemed necessary by the operator to maintain reliability. The reserve requirement is a construct defined to ensure that the system can recover from its most severe single contingency. Maintaining that requirement is not a price sensitive economic decision. The efficient price results from the economic dispatch required to meet the target reserve level. The efficient price does not result from an assigned value on an administrative price schedule that equals neither the operator's nor the customers' marginal value of reserves.

4. Reserve Market Uplift Does Not Warrant the Extended Sloping ORDC, but Reveals Other Flaws That the March 29th Complaint Does Not Resolve.

PJM asserts that the level of uplift payments in the reserve markets is evidence that the markets are not working and that the proposed ORDC is required. PJM is incorrect. PJM did not actually examine the reasons for uplift in the reserve markets prior to reaching its conclusion. The observed uplift is a result of multiple factors all of which inflate the opportunity cost calculations which are the source of the uplift payments, including the way in which inflexible resources are committed and paid, and the mismatch between the prices at which offers are calculated and paid for flexible units. Uplift is also inflated by the failure to appropriately reflect start and no load costs in the calculations. These issues need to be addressed in a targeted way. Using these issues as a rationale for a dramatic change to reserve pricing is not an effective way to address the actual issues.

The PJM Answer shows the amount of uplift paid for synchronized reserve market lost opportunity costs. PJM declares the synchronized reserve market dysfunctional based on the fact that lost opportunity cost uplift payments constitute 63.9 percent of production costs.[14] Examination of the lost opportunity cost payments shows that they result from pricing and settlements issues that are not addressed by the March 29th Complaint. The reasons for uplift based on synchronized reserve lost opportunity cost payments include incorrect settlements calculations, and a mismatch between the dispatch interval and the pricing interval.

Additional issues in nonsynchronized reserve lost opportunity cost payments include use of IT SCED prices instead of RT SCED prices to clear reserves, exclusion of start and no load costs from the lost opportunity cost calculation, the use of a five minute payment, and special arrangements between PJM and market sellers regarding nonsychronized reserve eligibility. Details regarding the issues with reserve market lost opportunity cost uplift payments are included as Attachment A.

While the level of uplift in the synchronized reserve market is a reason to question the detailed operation of that market, it is not a reason to implement PJM's proposed ORDC. There are targeted and specific solutions to the identified issues. The uplift issue is not new. The Market Monitor has pointed out for years that the level of uplift is an indicator of an issue in the synchronized reserve market.[15] Inflating prices with the proposed extended sloped ORDC will not resolve the need for or issues with the lost opportunity cost payments. This is an example of an issue that should have been identified prior to the ORDC filing and addressed.

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14 Keech Affidavit at 19 & 20; PJM Answer at 28.

15 *See* the 2018 State of the Market Report for PJM, Vol. 2, Section 10: Ancillary Service Markets (May 9, 2019).

B. The June Answers Fail to Address Fundamental Flaws in PJM's Proposal.

1. The Extended Sloping ORDC is Not a Ramping Product.

PJM claims that the March 29th Complaint proposes an ORDC that effectively functions as a ramping product.[16] PJM is wrong. A ramping product is not the same as primary or secondary reserves. A ramping product considers the upcoming net load forecasts for consecutive upcoming market intervals, as opposed to the single upcoming interval. A ramping product holds back ramping capability to meet changes in load in multiple upcoming consecutive market intervals, not for a contingency.[17] The ramping capacity is needed in addition to the minimum synchronized and primary reserve requirements. The method for constructing the proposed extended sloping ORDC is not based on predicting upcoming energy needs for multiple future intervals. While it is not clear that PJM needs a ramping product, a discussion focused on the actual details of ramping product options would be a constructive alternative to PJM's unsupported and vague assertions in this filing.

2. PJM Cannot Show that Its Proposal Would Lead to a More Flexible PJM Fleet.

PJM does not and cannot show that the PJM ORDC proposal would provide incentives for flexibility. PJM claims that its proposal will provide an incentive for increased resource flexibility because PJM would clear more reserves at higher prices and that these reserves would be provided by flexible resources. PJM cannot, and does not propose to, raise reserve market revenues in a vacuum. The proposed changes to the reserve market change LMP, which changes net revenues, which changes capacity market prices, which together affect investment, and retirement decisions for all resources no matter how

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16 PJM Answer at 36.

17 *See* California Independent System Operator, 156 FERC ¶ 61,226, Docket No. ER16-2023-000 (September 26, 2016).

flexible. The largest impacts of PJM's proposal are on the energy market and on the capacity market, assuming that the impacts on the capacity market are allowed to occur. The simulation results show substantial increases in revenues to coal and nuclear generators under the March 29th Complaint's proposal.[18] Delayed retirement of older, inflexible resources will crowd out investment in newer, more flexible resources. The increase in revenues would flow to inflexible resources without any strategic change in the offer behavior of these units.[19] Neither the arguments of PJM's Keech nor Webster's study consider the actual investment and retirement decisions that determine the composition of the PJM fleet. PJM's simplistic view of the markets, evaluating only the change in the reserve market from the perspective of a single resource and ignoring the competitive market equilibrium outcomes, is not convincing.

a. Profits Are Determined in Dollars Not Percent.

Witness Keech states that in evaluating the revenue changes in the energy and reserve markets, "it is more appropriate to consider these changes on a percentage basis to gauge the impact of design changes, as it normalizes the sizes of the markets."[20] Normalizing the size of the markets by focusing on percent changes in revenues instead of dollars, as Witness Keech suggests, is illogical. Actual suppliers decide whether to enter or exit the market based on dollars. Whether revenues cover the fixed cost of investments is a matter of dollar, not percent, increases in revenues. For example, a one dollar increase in LMP (2.8 percent) would increase the annual net revenues of the average PJM nuclear plant

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18 May 15th Protest at Attachment B.

19 The Market Monitor's argument regarding delayed retirement of inefficient fast start resources that PJM cites at 37 n.114 is not the same. In the fast start case, the inflexible unit is a block loaded combustion turbine or diesel engine that runs on the margin in the energy market and receives most of its revenue from the capacity market. Its benefits under fast start pricing rely on setting higher prices for other units. An inflexible baseload unit receives substantial net revenues from the energy market and benefits from higher prices without setting prices or exercising market power in the energy market.

20 Keech at 5.

by $15.7 million, enough to change the net revenue from a loss to a gain for at least one existing PJM nuclear plant, and therefore change the market signal from retirement to continued operation.[21] Meanwhile, a one dollar increase in the synchronized reserve price (18.6 percent) would only increase the net revenues of the average PJM combined cycle plant by $48,000 per year, which is not enough to create profitable opportunities for investments in flexibility. On the other hand, the capacity market price changes due to the entry or exit decision of either resource could change investment and retirement decisions for all resources.

Witness Keech argues (at 5–6) that it is reserve market revenues that provide incentives for flexibility. This is an incorrect, narrow view of the market. No current technology, except for a small MW quantity of batteries providing regulation, relies on ancillary service revenues alone. Resources make entry, exit, and investment decisions based on revenues from all markets, and the energy market is the largest share of those revenues.

b. The Flexibility Study Fails to Provide Relevant Results.

PJM includes the Webster report claiming that it provides "further support of the conclusion that that PJM's reforms will incentivize the development of flexible resources."[22] Webster's flexibility study fails to provide relevant results and does not demonstrate PJM's assertion that its ORDC benefits flexible units. The study evaluates the potential increase in revenue to an ERCOT combined cycle that increases flexibility when the current ORDC is replaced with the proposed ORDC. The study claims to assess the financial incentives of the investment separately for three different ERCOT combined cycles. However, the study does not discuss, reference, mention or quantify the profitability of the investments. The study does not discuss, reference or make any mention of the costs of the investments. The study

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21 For analysis of first and second quarters of 2019.

22 PJM Answer at 39.

does not discuss whether the investments would be profitable. The study does not discuss the profitability of other investments, e.g. investments that would make more base load type operation more profitable.

The results are not representative of the PJM region or of the PJM market. Evaluating PJM's proposal as if only one resource type in the market will respond with an investment is an unrealistic, overly simplistic assumption. Of course, multiple resources and multiple resource technologies would respond to the market design change. PJM's proposal will increase energy prices significantly. The response of multiple resources would change prices in the energy, reserve, and capacity markets. All of which the study ignores by only evaluating a single resource's and a single resource type's investment decision. The study simply shows that at least one resource, of a specific type, could increase gross revenues from higher prices if nothing else in the market changed, at least in the ERCOT market. The study does not establish that the March 29th Complaint's proposal would lead to a more flexible PJM fleet. PJM has not demonstrated that more flexible units will receive a unique or even disproportionate incentive from the higher prices. PJM has not demonstrated that its proposed ORDC is an effective, efficient or competitive way to incent increased flexibility. PJM has not addressed the issues in its existing rules that fail to incent flexibility.

c. The Simulations Show High Increases in Revenues for Inflexible Nuclear and Coal Units.

PJM asserts that the Market Monitor's conclusion that the March 29th Complaint's proposal supports inflexible resources depends on the choice of the simulation base case.[23] PJM is incorrect. The simulation result that nuclear units, which are completely inflexible, and coal units, which have inflexible parameters, benefit is true regardless of the choice of Case A or Case B as the simulation base case. Tables 9 and 10 of the Market Monitor's ORDC Simulation Results report show an annual increase in revenue of $110 million, or

[23] PJM Answer at 38.

$3,159 per MW-year, for nuclear units and $144 million, or $2,230 per MW-year, for steam coal units using Case B as the base case, as PJM suggests.[24] The increases in revenue are larger using Case A as the base case. Rather than sponsoring a study based on ERCOT data, PJM should have examined the results of its own simulations to understand the impact of its proposal on inflexible units.

d. PJM Never Discusses More Targeted Approaches to Increasing Flexibility

PJM fails to discuss more targeted and more cost effective ways to increase incentives for flexibility. These include implementing improvements to PJM's combined cycle modeling capability to increase the extent to which PJM markets can take advantage of the already incredible flexibility of combined cycle plants. The current PJM combined cycle modeling provides incentives to block load large combined cycles which are capable of operating in multiple modes. With the introduction of five minute pricing and five minute settlements, the benefits of improved combined cycle modeling are even more significant than under hourly pricing.

3. PJM Does Not Justify the Maximum Price on the Proposed ORDC.

a. An ORDC Penalty Factor Less Than $2,000 per MWh Is Consistent with Reliable Grid Operation.

With reference to the flat part of the ORDC at reserves less than the reserve requirement (MRR) and with a proposed price of $2,000 per MWh, PJM's Rocha Garrido claims (at 10) that an ORDC price lower than $2,000 per MWh is "inconsistent with operating the grid securely and reliably" even when the loss of load probability is substantially less than one hundred percent. This is clearly not an accurate statement. Other RTOs use ORDCs that gradually increase to the full penalty value as the magnitude of the shortage increases and the loss of load probability correspondingly increases, while

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24 *See* Market Monitor, ORDC Simulation Results: Version 2, Revised, Table 9 and Table 10 (May 24, 2019), <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_ORDC_Simulation_Results_Version_2,Revised_20190524.pdf>.

operating the grid securely and reliably. For example, MISO's Market-Wide ORDC is a step function with the lowest price level at $200 per MW for reserves shortages that are less than four percent of the reserve requirement, and higher prices as the shortage MW increase.[25] MISO does not reach its maximum shortage price until reserves decline to four percent of the requirement. SPP employs a similar shortage pricing scheme.[26] In fact, PJM itself does not take all emergency actions available to resolve most shortages, which PJM calls transient shortages. PJM has stated that transient shortages "incorrectly imply that a Reserve Zone or Reserve Sub-zone is experiencing a reserve shortage."[27]

b. PJM's Proposed ORDC Probability Calculation Is Flawed.

PJM's construction of its probability distribution is flawed in two significant ways. The use of an indirect proxy is less accurate than a direct measurement of the change in reserves, and the reasons for using a proxy are never explained. The use of 30 minute forecasts and a 30 minute window for forced outages to compute the sample observations is not consistent with the actual level of uncertainty in RT SCED solutions. A 15 minute look ahead timeframe is consistent with the actual level of uncertainty in RT SCED solutions. If PJM's approach to the development of an ORDC were followed, direct measurement of reserve levels and use of a 15 minute look ahead timeframe would provide a more accurate calculation than PJM's approach.

Instead of directly measuring the amount of available reserves, PJM uses the sum of load forecast error, net of wind and solar generation forecast error, and unforced outage MW as a proxy for the change in reserves. The PJM Load/Customer Coalition notes that ERCOT's ORDC calculations differ from PJM's in that ERCOT's ORDCs are based on a

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25 *See* Section III in "Schedule 28, Demand Curves for Operating Reserve and Regulating Reserve," July 8, 2019, <https://www.misoenergy.org/legal/tariff/>.

26 *See* Market Protocols SPP Integrated Marketplace § 4.1.5.2, Southwest Power Pool, April 17, 2019, <https://www.spp.org/spp-documents-filings/?id=20867>.

27 PJM Transmittal Letter, Docket ER17-1590-000 (May 12, 2017) at 4.

probability distribution of actual changes in the operating reserves.[28] Witness Griffey also states that "PJM appears to take this proxy approach because it does not have faith in its current assessment of available reserve capability."[29] Witness Rocha Garrido responds that the PJM approach is not a "proxy approach" since the change in reserves is equal to the sum of load forecast error, net of wind and solar generation forecast error, and unforced outage MW.[30] But PJM's method is by definition a proxy approach because it uses proxies to measure the behavior of reserves rather than measuring reserves directly.[31] In fact Hogan and Pope describe (at 6) PJM's method as "a workable approximation."

The PJM method also introduces additional measurement error. The direct approach for obtaining sample observations would only require collecting observations of a single variable, the available reserves. The PJM method on the other hand has four variables. Measurement errors are always a concern in statistical analysis and a good way to reduce measurement error is to reduce the number of variables. An approach that measures the change in reserves directly would be a superior method to the one employed by PJM. Witness Rocha Garrido does not respond to Griffey's suggestion that PJM does not have the ability to measure available reserves.

PJM's current operational practices are inadequate to accurately measure available reserves at any given point in time. PJM market tools are not designed to fully account for all generator characteristics. Consequently, PJM market and operational tools make several simplifying assumptions about generators' operational parameters. PJM system operators lack complete information to accurately measure the amount of supply available for energy

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28 *See* Protest of the PJM Load/Customer Coalition, Docket No. EL19-58-000 et al. (May 15, 2019) at 28 ("PJM Load Protest").

29 *See* PJM Load Protest, Attachment B, Affidavit of Charles S. Griffey at para. 8 (May 15, 2019).

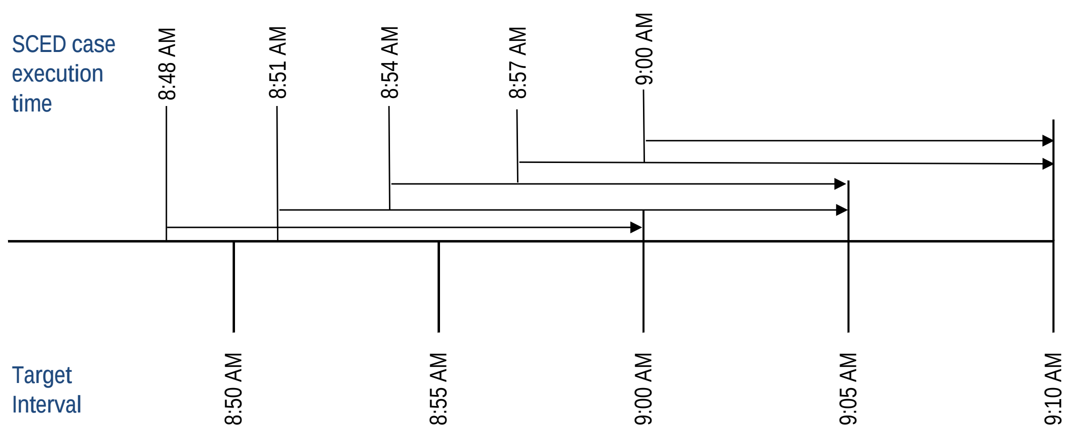
30 *See* Rocha Garrido at 16.

31 For example, generators deviating from the dispatch instruction impact the level of available reserves and are not accounted for in the PJM method.

and reserves. In its May 15th protest, the Market Monitor described in detail the limitations faced by PJM to accurately measure reserves.[32]

PJM's Witness Rocha Garrido repeats (at 28–30) the flawed reasoning in his initial affidavit to justify use of the 30 minute look ahead period for measuring uncertainty. Exelon echoes (at 30–31) the flawed reasoning of Witness Rocha Garrido. The look ahead period for the forecasts used in RT SCED is 10 to 15 minutes. Figure 1 shows the timeline of RT SCED execution with respect to each five minute interval in PJM. A set of RT SCED cases are executed (begin to solve) every three minutes. These cases solve for a target interval that is a minimum of 10 minutes to a maximum of 14 minutes in the future when they begin to solve.

Figure 1 RT SCED execution and target interval



However, it is inaccurate to add the 10 minute response time for reserves to the 15 minute look ahead time of the forecast.

The PJM proposed extended sloping ORDC is formed by multiplying the reserve shortage penalty price by the probability of not meeting the reserve requirement. PJM phrases this as PBMRR, where PJM defines PBMRR as the "probability of failing to meet

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32 *See* Protest of the Independent Market Monitor for PJM, Docket No. EL19-58-000 (May 15, 2019) at 59–61.

MRR."[33] The MRR is the minimum reserve requirement. The purpose of reserves procured to meet the MRR at any instance is to respond to a contingency that might happen in the 10 minutes following that instance. That contingency is currently the single largest contingency on the system (also referred to as the N-1 contingency). That is the definition of primary and synchronized reserves in PJM. If PJM's rationale for valuing reserves beyond the MRR is that they mitigate the uncertainty associated with what could happen within the 10–14 minutes between when SCED is solved and the target interval, the only relevant forecast error is the forecast for the SCED target interval. The uncertainty in the 10 minutes following the target interval is the reason for procuring reserves to meet the MRR in the first place. This uncertainty in the 10 minutes following the target interval should not again result in additional reserves beyond the MRR.

c. *The Highest Reserve Penalty Factor Need Not Exceed the Highest Generator Offer.*

In the March 29th Complaint, PJM asserted that $2,000 per MWh is "consistent with the actions that system operators will take to maintain reserves and allow those actions to be reflected in market clearing prices."[34] PJM's Answer argues for a value even higher than $2,000 per MWh based on the highest potential value of the congestion component of LMP. PJM's Answer is incorrect. The congestion component of LMP allows for the economic dispatch of the market to reliably avoid the violation of transmission constraints. The congestion component of LMP works together with the jointly optimized reserve market price to allocate reserves to resources that are not needed for the relief of transmission constraints.

PJM's Answer argues that congestion costs raise the cost of maintaining reserves, because a resource relieving a constraint faces a higher LMP than other resources. In the specific scenario posed by PJM, a resource with an unusually high distribution factor to a

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[33] *See* Rocha Garrido at 5–6, para. 17 (March 29, 2019).

[34] March 29th Complaint at 11.

violated transmission constraint sees an LMP of $1,300 per MWh.[35] For the constraint to reach the $2,000 per MWh shadow price, there can be no resource on the system able to relieve the constraint for that market interval. That constraint is a reliability issue occurring with a 100 percent probability. If the resource were backed down to provide reserves, it would exacerbate and likely prolong the constraint violation. It does not make sense for the market to place a higher value for reserves than for energy on that particular resource while it relieves a violated transmission constraint. To do so would endanger reliability. The market should procure reserves on another resource that does not relieve the violated constraint. PJM's argument that transmission constraint penalty factors imply a need for a higher reserve penalty factor is not helpful and does not support raising the reserve penalty factor above the highest incremental offer on the system.

4. The Proposed Extended Sloping ORDC has no Theoretical Foundation.

Witnesses Hogan and Pope's theory for reforming reserve markets defines the value of operating reserves based on the value of lost load net of the incremental cost of marginal generation multiplied by the loss of load probability.

PJM's proposed implementation, detailed in the March 29th Complaint, does not use the Hogan and Pope theory. PJM does not use the value of lost load or the loss of load probability. Under PJM's proposed method, the ORDC curve is derived by multiplying the $2,000 per MWh penalty by the calculated probability of falling short of the minimum reserve requirement for a given level of scheduled reserves.

The Hogan and Pope theory attempts to derive an ORDC from first principles, estimating an actual economic cost incurred by consumers based on the assumed VOLL and an estimate of the LOLP from actual reserves. PJM's approach is not based on the Hogan and Pope theory. PJM does not attempt to measure actual economic costs to consumers. PJM's reserve penalty factor is an administratively imposed value based on

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[35] PJM Answer at 51.

worst-case scenario emergency actions, and PJM's PBMRR is calculated from forecast errors that do not accurately measure reserves. That Witnesses Hogan and Pope call PJM's method a "workable approximation" is not correct as the PJM approach is not an approximation of the Hogan and Pope model in any sense.

The ultimate of a system operator for procuring reserves is to reduce the chance of involuntary load curtailment, also referred to as loss of load probability. But, unlike the Hogan and Pope theory, PJM's valuation of reserves under its proposed implementation is not tied to the goal of avoiding involuntary load curtailment.[36] In PJM's implementation, reserves have value only to the extent they reduce the likelihood of falling below the minimum reserve requirement.

Exelon Witness Schnitzer argues that the maximum price for reserve that can occur in the RTO region, outside the MAD reserve region, is $8,000 per MWh.[37] Since this value is in the neighborhood of $9,000 per MWh, used by ERCOT to represent the value of lost load in its ORDC curve, Witness Schnitzer concludes that the PJM's valuation of its reserves is generally consistent with the value of lost load based valuation used in the ERCOT energy market. Witness Schnitzer ignores the fact that PJM's approach is not related to the ERCOT (Hogan and Pope) approach to defining an ORDC.

Witness Schnitzer's comparison is also misleading because the highest price that can occur in RTO region, outside MAD reserve region, could exceed $8,000 per MWh. Witness Schnitzer wrongly assumes that the maximum energy price cannot exceed the highest offer

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[36] PJM stated, without providing any evidence, that the PJM's Capacity Market allows PJM to limit their focus only to maintaining minimum reserve requirements. *See* March 29th Complaint, Attachment D: Affidavit of Adam Keech at para. 9.

[37] Schnitzer at 12.

price of the generator dispatched.[38] Within the MAD reserve region, which Witness Schnitzer omits for his comparison, the highest prices could exceed $14,000 per MWh.

Exelon, drawing on conclusions made by Witness Schnitzer, asserts that the combined effect of cascading ORDCs results in an outcome that is entirely consistent with a VOLL based approach. Exelon's conclusions are based on a selective comparison of price outcomes under extreme reserve shortage conditions in both markets.

5. PJM Presents an Overly Narrow View of the Market Simulations.

In its May 15th Protest, the Market Monitor presented a broad set of results and comparisons from the simulations as an alternative to PJM's narrow view of the simulation results, giving the Commission the opportunity to critically evaluate the results rather than relying on PJM's limited interpretation.[39] PJM argues that the Market Monitor's analysis of the results is incorrect.[40] PJM claims that the relevant base case is Case B, which removes all ex post uneconomic commitments from the market. Uneconomic commitments are part of the reality of the market. Uneconomic commitments are part of the status quo that PJM's Pilong claims the proposed ORDC will ameliorate.[41] PJM's arguments are inconsistent, on the one hand excluding the impacts of unit commitment changes in presenting the simulation results to reduce the market impact, while on the other hand claiming the changes in unit commitments as benefits.

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38 *See* O'Neill R. P, Mead D. and Malvadkar P, "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena," *The Electricity Journal* 2005; 18(2) at 19–27.

39 Protest of the Independent Market Monitor for PJM, Docket No. EL19-58-000 et al. and ER19-1486. (May 15, 2019) ("May 15th Protest").

40 PJM Answer at 60.

41 Keech at 12 n.28.

6. **Failure to Consider the Interaction with the Capacity Market is Not Just and Reasonable.**

   a. ***There Is a Tight Interaction Between the Capacity and Energy Markets.***

The argument about how to reflect the impact of the energy market changes in the capacity market could be avoided entirely if the Commission were to adopt the moderate proposal of the Market Monitor. The need to have a transition mechanism for cleared auctions for future delivery years is entirely a result of the radical nature of the PJM ORDC proposal and the resultant increase in energy market revenues. It is clear to all that, by design, there is a tight integration between the capacity and energy markets and that when energy and reserve market revenues increase, capacity market revenues decrease. It is clear to all that, by design, PJM's ORDC proposal will increase energy revenues and reduce capacity market revenues. It is clear to all that generators will receive substantial windfall profits. The Market Monitor calculates that the total increase in payments by load to generators would be $9.2 billion over seven years. The generators, supported by PJM, have made it clear that they want to keep the windfall profits. While that desire is understandable, it is not efficient, not competitive, not fair and not consistent with the fundamental structure of the integrated PJM market design and is not just and reasonable as a result. The generators' position would transform the missing money problem into the windfall profit problem through the simultaneous implementation of two substitute approaches to the missing money problem.

The impact of PJM's proposed ORDC on the capacity market would occur for auctions already cleared but for which the delivery year has not yet occurred, and for auctions not yet cleared. PJM and Exelon fail to recognize both impacts and assert that associated changes to the capacity market design are not required for either cleared auctions or uncleared auctions.

Exelon's assertion that the $2 billion increase in energy revenues associated with PJM's proposed ORDC, plus the $1 billion increase in energy revenues associated with fast start pricing, are simply "an inherent part" of the forward looking capacity market construct, is not credible. Dramatic changes to the market design are not an inherent part of the capacity market design. These changes were not contemplated and could not have been contemplated by market participants. These changes are not comparable to any prior changes to the energy market since the introduction of the three year forward capacity auctions in 2007. Exelon contradicts its own approach (at 22–28) when it asks the Commission to consider expected rather than actual normal market changes in prices if it implements a transition mechanism.

PJM's proposed approach here of ignoring the market impacts is not consistent with PJM's approach, supported by Exelon, that created a transition mechanism for the Capacity Performance construct, which was a less significant change to the markets than PJM's proposed ORDC.[42]

Exelon also asserts that generators have already sold their positions and would not benefit from higher energy market revenues. Exelon asserts that the energy and ancillary services offset is minor. The fact that net CONE times B is the official offer cap does not mean that competitive offers are based on net CONE. Competitive offers continue to be based on net ACR, which is gross ACR minus the EAS offset, which Exelon appears (at 27) to recognize.

For auctions that have not yet cleared, Exelon asserts that it is just too hard to calculate a forward looking offset and that the historical approach will gradually incorporate the changes to the energy market revenues. Calculating a forward looking EAS offset is not difficult. Actual developers and generation owners use forward looking calculations of energy market revenues. Actual generation offers are based on forward looking calculations. Exelon itself, as with almost all market participants, makes forward looking calculations. While it is understandable that Exelon, who benefits from a delayed increase in the offset, would like to postpone the impact of the increased energy market

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[42] Comments and Partial Protest of Exelon Corporation, Docket No. ER15-623-000 (January 20, 2015).

revenues on the capacity market, the change in energy market revenues should be reflected in the next capacity market run after any decision on PJM's proposal.

PJM asserts (at 61) that no evidence has been advanced that changes to the capacity market EAS offset are needed. It is not clear why an unexpected and unanticipated increase in energy and reserve market revenues of $2 billion is not evidence. Based on PJM's filing, this meets PJM's standards for what comprises evidence. If PJM believes that the change to the energy and reserve market revenues is de minimis, it is not clear why they made this filing.

PJM asserts that the EAS offset is wrong by design. This is belied by the fact that PJM argued for a forward looking EAS offset in the prior Triennial Review process before abandoning the argument at the end.[43] Brattle recommended a forward looking EAS offset in the Brattle Report to PJM in the most recent Quadrennial Review.[44] Even in the EPFSTF process, PJM proposed to use a forward looking EAS offset based on PJM simulations rather than forward markets.[45] While the Market Monitor agrees that PJM simulations are not an appropriate basis, PJM consistently argued for a forward looking offset. Only at the end of the EPFSTF process did PJM decide, for no stated reason, to abandon the forward looking approach in favor of the historical approach. PJM's change of heart did occur after vociferous statements of opposition to forward looking offsets by generators.[46]

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43 *See* PJM, "Cost of New Entry Estimate for Combustion Turbine and Combined Cycle Plants in PJM," Docket No. ER14-2940 re Triennial Review (September 25, 2014).

44 See PJM. Docket No. ER19-105-000 "PJM Cost of New Entry Combustion Turbines and Combined-*Cycle* Plant with June 1, 2022 Online Date," and "Fourth Review of PJMs Variable Resource Requirement Curve," re Quadrennial Review (October 12, 2018)

45 PJM presentation presented to the January 23, 2019 meeting of the EPFSTF. "Price Formation Transition," <*https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20190123/20190123-item-04b-pjm-price-formation-transition.ashx*>.

46 PJM, Energy Price Formation Senior Task Force (EPFSTF), "PJM Reserve Markets-Calpine Proposal Energy Price Formation Initiative"(December 20, 2018) <*https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20190104/20190104-item-07-calpine-proposal.ashx*>.

PJM does not appear to believe in its own market design as PJM asserts that when EAS revenues are high, capacity market prices need to be artificially propped up. The reasons for arbitrarily setting the maximum price at the higher of gross CONE or 1.5 times Net CONE was to prevent the capacity market price from decreasing at a time when there was no effective scarcity pricing mechanism. With PJM's ORDC that would no longer be true and there would no longer be even an argument for artificially propping up the capacity market. Either PJM believes there is an offsetting relationship between the two markets or it does not. Customers should not be required to pay for belt and suspenders in a competitive market. The generators' approach would take administrative pricing to whole new levels by artificially sustaining a capacity market price above the competitive level.

PJM argues that forward looking calculations will not be 100 percent accurate and therefore the historical approach should be used despite the obvious mismatch. PJM's argument is illogical:

> As PJM noted, this approach was 'consciously chosen' with the knowledge that any predictions of actual future year EAS revenues will likely be incorrect, and therefore using actual historic revenues received is a more rational solution, given the fundamental timing mismatch between the years when actual EAS revenues are received and when future capacity revenues are realized.[47]

PJM ignores the actual way in which competitive offers are formed and how actual competitive markets function. Market participants are always looking forward, and market participants recognize that their forward looks are the best calculations available. Willfully using incorrect historical EAS offsets because the future is uncertain is illogical and unsupportable. The only reason to take this approach is to sustain the windfall profits for as long as possible.

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[47] PJM Answer at 64.

Calpine/LS Power make interesting arguments about the offset. Calpine/LS Power argue that the capacity market plays a core role in the PJM market design and should not be abandoned. Calpine/LS Power point out the difference in interests between the owners of nuclear plants and merchant generators. Calpine/LS Power are essentially arguing against PJM's efforts to supplant the capacity market with the energy market. PJM and Exelon and Hogan and Pope all assert the benefits of the energy market with the proposed ORDC in providing better incentives than the capacity market. But Calpine/LS Power do not agree. Calpine/LS Power state bluntly that if there is to be a forward looking EAS offset, the Commission should reject PJM's filing. Given that Calpine/LS Power must understand that a forward looking offset is the only way to ensure that the energy market and the capacity market are coordinated, Calpine/LS Power are effectively arguing that PJM's proposal should be rejected.

b. There is No Legal Justification for Ignoring the Capacity Market.

PJM argues that "the fact that a filing may make other provisions unjust and unreasonable does not make that filing unjust and unreasonable."[48] PJM's reliance on *AEMA* is misplaced. *AEMA* does not stand for the proposition that the Commission cannot reject a 205 proposal because it renders the PJM market design, whether considered in whole or in part, unjust and unreasonable. The Court's point was exactly the opposite.

The Court stated in *AEMA*:

> The Commission could find that PJM's proposed capacity market rules were just and reasonable under *section 205* even though they rendered some rules in PJM's energy market unjust and unreasonable. Effects on other tariff provisions are not dispositive. The Commission has broad discretion to balance competing concerns. 'If the total effect of the rate order cannot be said to be unjust and unreasonable,' we will defer to the Commission's finding. [emphasis in original]

48 PJM Answer at 63, citing *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 664 (D.C. Cir. 2017) ("*AEMA*").

The Court clearly and appropriately leaves the determination of what is just and reasonable to the Commission. Deference applies to the Commission as the administrator of the Federal Power Act. The Court does not require that the Commission extend any deference to a section 205 proposal of a public utility it is charged regulate. If the Commission determines that PJM's proposal would render existing aspects of the PJM market design unjust and unreasonable, the Commission can reject it.

Moreover, *AEMA* concerns Section 205 proposals. PJM's proposal in this proceeding must be evaluated under Section 206. PJM's proposal is entitled to no deference under Section 206. PJM has not met its burden to show that its existing rules are unjust and unreasonable. If, nevertheless, there is such a finding in this proceeding, the Commission may exercise its discretion to determine a solution with no deference to PJM's proposal. The Market Monitor has provided options that would improve the rules for the reserves markets without rendering other aspects of the PJM market design unjust and unreasonable. There is no reason to direct rules changes in this proceeding that would render any aspect of the PJM market design unjust and unreasonable.

EPSA argues (at 3–4) that the Market Monitor's comments identifying elements of the RPM market design that would be made unjust and unreasonable if PJM's proposal was accepted are procedurally improper because PJM "did not challenge the lawfulness of the EAS offset or the RPM rules in general." The Market Monitor does not challenge any existing RPM rule or any PJM market rule in this proceeding. The Market Monitor recommends rejecting PJM's filing with prejudice because PJM has failed to prove any aspect of its market design in unjust and unreasonable in this proceeding. Arguments exposing the full range of serious flaws in PJM's proposal nevertheless remain within the proper scope of this proceeding. Nothing is procedurally improper in pointing out how proposed rule changes harm the existing market design.

II. MOTION FOR LEAVE TO ANSWER

The Commission's Rules of Practice and Procedure, 18 CFR § 385.213(a)(2), do not permit answers to answers or protests unless otherwise ordered by the decisional authority. The Commission has made exceptions, however, where an answer clarifies the issues or assists in creating a complete record.[49] In this answer, the Market Monitor provides the Commission with information useful to the Commission's decision-making process and which provides a more complete record. Accordingly, the Market Monitor respectfully requests that this answer be permitted.

III. CONCLUSION

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

Respectfully submitted,

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49 *See*, *e.g.*, *PJM Interconnection, L.L.C., 119 FERC ¶61,318 at P 36 (2007)* (accepted answer to answer that "provided information that assisted … decision-making process"); *California Independent System Operator Corporation*, 110 FERC ¶ 61,007 (2005) (answer to answer permitted to assist Commission in decision-making process); *New Power Company v. PJM Interconnection, L.L.C.*, 98 FERC ¶ 61,208 (2002) (answer accepted to provide new factual and legal material to assist the Commission in decision-making process); *N.Y. Independent System Operator, Inc.*, 121 FERC ¶61,112 at P 4 (2007) (answer to protest accepted because it provided information that assisted the Commission in its decision-making process).

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Dated: July 15, 2019

CERTIFICATE OF SERVICE

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

Dated at Eagleville, Pennsylvania,
this 15th day of July, 2019.

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Attachment

Reserve Uplift Issues

The Independent Market Monitor for PJM

July 15, 2019

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Background

Units in PJM are compensated for lost opportunity cost (LOC) when their output is reduced to provide ancillary services. In the Regulation, Synchronized Reserves and Nonsynchronized Reserve Markets, PJM clears resources based on the LOC of such resources to provide energy. The compensation from the ancillary services market should make the units indifferent between providing energy or any of the ancillary services.

In the Synchronized Reserve Market, the Market Clearing Price (MCP) is comprised of the marginal unit's synchronized reserve offer plus the marginal unit's LOC. When the Market Clearing Price does not cover the unit's LOC, PJM makes the unit indifferent by providing an additional LOC payment. Therefore, in the Synchronized Reserve Market there are two payments, the MCP payment, which is the cleared MW times the MCP and the LOC uplift payment.

Synchronized reserves are provided by flexible and inflexible resources. Flexible resources are those that can be assigned and deassigned synchronized reserves every five minutes. These resources are typically online units with available ramping capacity. Inflexible resources are those that can only be assigned and deassigned synchronized reserves every hour. These resources are combustion turbines in condensing mode and demand response.

In the Nonsynchronized Reserve Market, the Market Clearing Price (MCP) is comprised of the marginal unit's synchronized reserve offer (if the Primary Requirement was met by a synchronized resource on the margin) plus the marginal unit's LOC. When the Market Clearing Price does not cover the unit's LOC, PJM makes the unit indifferent by providing an additional LOC payment. Therefore, in the Nonsynchronized Reserve Market there are two payments, the MCP payment, which is the cleared MW times the MCP and the LOC uplift payment.

Nonsynchronized reserves are provided by flexible resources. Flexible resources are those that can be assigned and deassigned nonsynchronized reserves every five minutes. These resources should be offline units that can start within 10 minutes. These resources are typically combustion turbines with remote start capability.

Since in both the Synchronized Reserve and Nonsynchronized Reserve Markets, the reserve requirement is met by flexible resources, there should not be an LOC uplift payment to these resources. Flexible resources can be assigned and deassigned reserves every five minutes. Therefore, the MCP of the both markets should always cover the LOC of the flexible resources, otherwise, the resource should have not cleared the reserve market.

The Market Monitor identified several significant flaws in the current Reserve Market clearing and LOC uplift compensation that have led to excessive LOC uplift payments in the reserve markets.

Reserve Market Clearing Process

SCED and LPC Interval Mismatch

RT SCED solves the dispatch problem for a target interval that is generally 10 – 14 minutes in the future. RT SCED also cooptimizes energy, regulation and reserves. An RT SCED case is approved and clears reserves from flexible generators. An approved RT SCED case is used to calculate LMPs in LPC. However, the target interval in LPC is consistently ahead of the target interval from the RT SCED case used for clearing reserves. This discrepancy leads to a mismatch between the cleared reserves MW and reserve clearing prices. Current PJM compensates cleared reserves MW based on the target intervals used by the RT SCED cases while using the market clearing prices based on the assigned intervals used by the LPC cases. SCED cases are typically 10 minutes ahead of the assigned LPC intervals. For example, if a marginal unit clears 10 MW of Synchronized Reserves in one interval with an MCP of $10/MW and 0 MW of Synchronized Reserves in the next interval with an MCP of $5/MW, the unit will receive $50 as an MCP payment and $50 as a LOC uplift payment because PJM will match the $5 per MW clearing price with the 10 MW assignment. This flaw is a result of a mismatch between RT SCED and LPC target intervals.

NSR Cooptimization Simplification

PJM is responsible for cooptimizing the procurement of energy and reserves. PJM RT SCED tool currently performs that task. It cooptimizes energy and reserves by determining the tradeoff between energy and reserves of every available resource. The prices resulting from the cooptimization should reflect an efficient market. One shortcut assumed by PJM was made in the procurement of Nonsynchronized Reserves. RT SCED does not perform unit commitment. It only dispatches resources already online. Therefore RT SCED cannot calculate the tradeoff of providing energy or nonsynchronized reserve from offline units. Instead, PJM uses estimated LMPs from IT SCED to allow RT SCED to clear nonsynchronized reserves. IT SCED is the PJM tool that can perform unit commitment, but it is not used to set LMP or reserve prices. The use of IT SCED LMPs in the procurement of Nonsynchronized Reserves results in an inefficient outcome that PJM resolves by compensating NSR resources with LOC uplift payments. This occurs whenever the estimated tradeoff calculated by IT SCED is less than the estimated tradeoff calculated by RT SCED. For example, if IT SCED expects prices to be $50 per MWh, the tradeoff of a $200 per MWh oil fired CT is zero. If in RT SCED an unexpected constraint binds and the RT LMP increases to $1,000 per MWh, RT SCED will still clear this unit as NSR because the cost is zero while the actual tradeoff is $800 per MW. Because of this issue, PJM will compensate that unit an LOC uplift payment of $800 per MW.

LOC Uplift Compensation

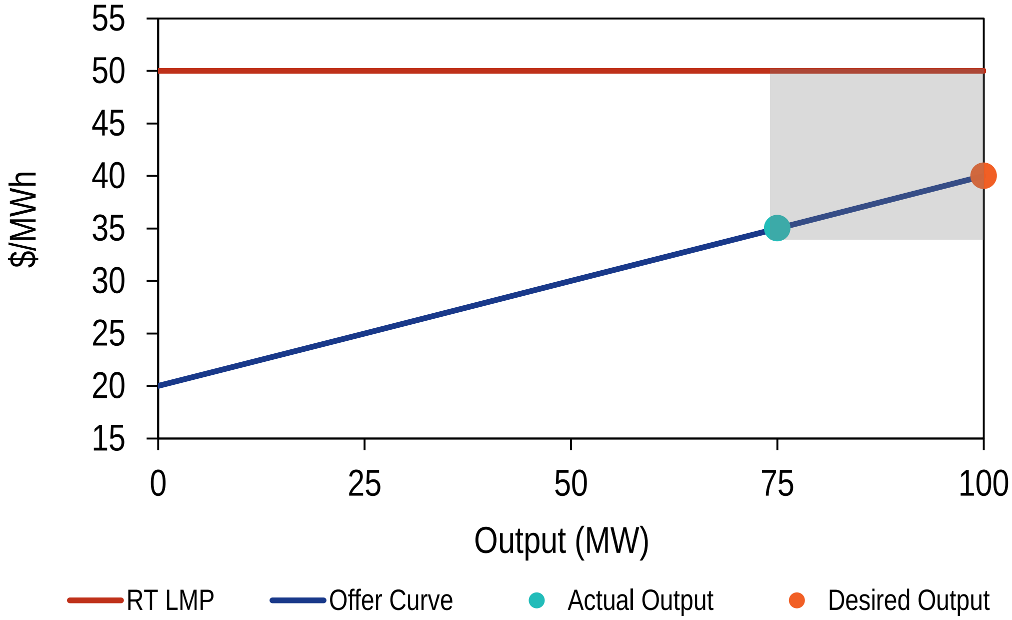
Other issues identified by the Market Monitor in the LOC uplift calculations increase the magnitude of the problem.

Incremental Offer Curve

The current LOC calculation in the SR and NSR Markets ignore the shape of the incremental offer curve. Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the lost opportunity cost in the reserve markets. In 2012, the Market Monitor identified that resources were being overcompensated for Energy Market LOC when backed down for their desired MW output, same action that resources must do to provide reserves. By using a single point, PJM understates the cost of the unit if asked to produce energy. In the LOC calculation, PJM assumes that the cost of the unit is flat and it does not increase as output increases. This is incorrect and leads to LOC overcompensation. PJM corrected this flaw in 2015.

Figure 1 shows the overcompensation graphically. In this example, the unit's output is reduced from its optimal economic dispatch to provide synchronized reserves. The unit clears 25 MW of reserves and produces 75 MWh of energy. The unit's optimal economic dispatch point is 100 MW since the LMP is higher than the unit's offer. On the margin, the unit has a LOC of $15 per MWh that results from the tradeoff of providing reserves and not energy. Because of the mismatch between RT SCED and LPC, the interval in which the unit clears 25 MW is assigned an MCP of $10 per MW. The $10 per MW does not cover the $15 per MWh LOC, therefore the unit will receive an LOC uplift payment. The Synchronized Reserve LOC uplift compensation is depicted by the grey are in the figure. It is calculated as the MW reduced to provide reserves times the difference between the LMP and the unit's offer at the actual output. This simplification ignores the shape of the offer curve and overcompensates the unit by an amount equal to the gray area under the offer curve. In this example, the unit received an MCP payment of $250 and an LOC of $125, the LOC calculated using the shape of the curve would have resulted in $62.50. If the MCP was assigned correctly, the unit's LOC would have been completely covered by the MCP and the LOC would have been zero.

Figure 1 Synchronized Reserves LOC Compensation Example



No Load and Start Costs

The NSR LOC compensation contains the same flaw identified by the Market Monitor and addressed by PJM in the Energy Market LOC compensation. In 2012, the Market Monitor identified that resources were being overcompensated for Energy Market LOC when scheduled in the Day-Ahead Energy Market and not called in real time because PJM did not account for the avoided no load and start costs in the LOC calculation. PJM corrected this flaw in 2015. The NSR LOC compensation contains the same flaw. NSR units are kept indifferent from providing energy or NSR by receiving an LOC compensation equal to the difference between the forgone revenues from the energy market and their energy offer. Currently PJM does not subtract from the forgone revenues the no load and start costs that NSR resources do not incur to provide NSR but that would have incur to provide energy. This exclusion incorrectly increases the amount of NSR LOC paid. For example, if a 50 MW unit clears the NSR Market with a $200 per MWh incremental offer, $1,000 per hour no load cost and a $5,000 start cost when the NSR MCP is $5 per MW, the unit will be compensated for LOC when the RT LMP is greater than $205 per MWh (incremental offer plus the NSR MCP). If the RT LMP is $300 per MWh, the resource will receive an LOC uplift payment of $95 per MWh. The LOC uplift payment will be equal to the LMP Desired MW times the difference between the RT LMP and the incremental offer minus the NSR MW times the NSR MCP. This calculates overstates the LOC of the resource because it does not take into account the no load and start costs. If the calculation included no load and start costs, the unit would not receive an LOC uplift payment.

Five Minute Compensation

Current rules calculate LOC on a five minute basis. This means that units receive an LOC payment during intervals in which it is economic for them run and receive the benefit of not being called on during intervals in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the intervals would not be economic. The operation may result noneconomic because LMPs do not support the commitment of the unit for its entire minimum run time, but the unit could still receive an LOC payment if during any interval the RT LMP exceeds the incremental offer of the unit. This is not the intent of LOC payments. LOC should be paid to resources to ensure that they operate following PJM's direction and not lose their profit. In the case of five minute interval calculations, units are not made indifferent, but are overcompensated compared to the compensation they would have received had they run. This incorrect simplification of the LOC calculations increases the amount of LOC paid to inflexible SR resources. For example, if a unit with a $200 per MWh incremental offer clears the NSR Market, the unit will receive an LOC uplift payment if the RT LMP is above the $200 per MWh plus the NSR MCP, if that only occurs during one interval in an hour while the other 11 intervals the LMP is considerably below the unit's incremental offer, it would have been not economic to commit the unit because the LMPs did not support such commitment. Regardless, PJM will compensate the unit for the one interval in which the RT LMP was above the cost of the unit, while ignoring the other 11 intervals in which the RT LMP was below the cost of the unit.

Other Issues

Currently PJM allows certain resources to clear the NSR Market while having a lead time (notification plus start times) greater than 10 minutes. According to PJM, PJM can enter into agreements with market sellers that submit lead times that exceed 10 minutes, if market sellers demonstrate by other means that they can meet the 10 minute lead time requirement to qualify as NSR. This is another cause of excessive LOC payments since these units cannot be committed to meet load or relieve transmission constraints within 10 minutes but are paid LOC as if they could. In 2018, these units received 55 percent of all NSR LOC, more than half of PJM's perceived problem with the NSR Market.