UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. EL19-58-000
v.	)	
PJM Interconnection, L.L.C.	)	
PJM Interconnection, L.L.C.	)	Docket No. ER19-1486-000

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Joseph E. Bowring
Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8051
joseph.bowring@monitoringanalytics.com

Jeffrey W. Mayes
General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

Catherine Tyler
Senior Economist
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8050
catherine.tyler@monitoringanalytics.com

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Pursuant to Rule 211 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] protests the complaint filed by PJM Interconnection, L.L.C. ("PJM") against its market rules on March 29, 2019 ("March 29th Filing"), as well as certain related tariff revisions.

The March 29th Filing purports to be about the reserve markets, but in fact proposes significant changes to the reserve markets, to the energy market and to the capacity market. The March 29th Filing addresses the design of the reserve markets but fails to establish that the current design is unjust and unreasonable. The March 29th Filing should be rejected for that reason. The March 29th Filing changes the calculation of energy prices but does not claim or establish that locational marginal pricing ("LMP") is unjust and unreasonable or that the existing scarcity pricing rules are unjust and unreasonable. The March 29th Filing

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1 18 CFR § 385.211 (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").

should be rejected for that reason. The March 29th Filing shifts scarcity revenues from the capacity market to the energy market but does not propose that capacity market revenues reflect that shift or claim or establish that the capacity market design is unjust and unreasonable. The March 29th Filing should be rejected for that reason.

There is no lawful basis for evaluating the flawed proposal in the March 29th Filing without the required showing that the existing market design, including design of the reserve markets, the energy market and the capacity market, is unjust and unreasonable. The March 29th Filing should be rejected because it fails to meet the standard for a Section 206 filing for the energy and capacity markets by failing to state the impact on the energy market and the capacity market and failing to request authority to make such changes.[3] The changes to the energy and capacity markets imply that PJM believes that these markets are not just and reasonable but PJM does not make this argument. The March 29th Filing fails to meet this burden and should be rejected without any consideration of proposed solutions.

Even if the March 29th Filing had met its burden to demonstrate that PJM's market design is unjust and unreasonable, the solution offered does not address the identified issues and would introduce new and complex market design problems with unintended consequences.

PJM has not explained why it is necessary to replace LMP with a nontransparent and complex administrative price setting process. Energy prices are not too low. Net revenues are not too low. Uplift is low. Installed reserves are well in excess of requirements. Reserve prices reflect economic fundamentals. PJM has not identified a current or expected problem to which the March 29th Filing is a solution. PJM has not explained why load should pay an increase of more than $1.7 billion per year. PJM has not explained why customers should be required to pay for reserves substantially in excess of the required level of reserves. Just and

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[3] 16 U.S.C. § 824e.

reasonable energy and reserve prices do not require a downward sloping Operating Reserve Demand Curve.

The March 29th Filing makes arguments that are overstated and arguments that are invalid, claiming that the markets are unjust and unreasonable, in order to implement PJM's preferred market design that cannot be submitted to the Commission as a Section 205 filing because PJM stakeholders rejected it.[4] The March 29th Filing does not establish that the markets are unjust and unreasonable or that its proposals are just and reasonable. The March 29th Filing should be rejected.

I. PROTEST

A. The Status Quo PJM Energy and Ancillary Service Markets Produce Just and Reasonable Rates.

1. PJM's Complaint Asks the Commission to Find Energy Market Pricing (LMP) Is Unjust and Unreasonable.

PJM masks the purpose of the March 29th Filing by waiting until page 102 to state the largest and most fundamental proposal in its complaint, "that the sloped ORDCs for clearing the reserve markets will interact with the energy market prices even when the minimum reserve requirements are being met." The result is scarcity pricing all the time, all hours of the day, all days of the year, regardless of actual shortage conditions. This is caused by the interaction of the extended downward sloping ORDC with LMP.

In concept, an extended downward sloping ORDC intends to reflect capacity shortages in energy market prices in the absence of a capacity market, and it is used for that purpose in ERCOT, the only market currently applying this market design. As described in Hogan and Pope's report, the purpose of the extended ORDC is to "connect the solution to the missing-money requirement to short-term dispatch operations and actions that

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[4] 16 U.S.C. § 824d.

maintain minute-by-minute reliability."[5] In other words, the purpose of the extended ORDC is the same as the capacity market. According to Hogan, the "operating reserve demand curve would reflect capacity scarcity."[6]

To claim that the March 29th Filing only applies to PJM's reserve markets is false and misleading. The March 29th Filing changes the calculation of energy prices and shifts scarcity revenues from the capacity market to the energy market, increasing energy market revenues but without a corresponding decrease in capacity market revenues. In fact, the March 29th Filing results from PJM's proposal to the Energy Price Formation Senior Task Force, as opposed to a nonexistent Reserve Price Formation Senior Task Force. The March 29th Filing misrepresents the nature of its complaint by only explicitly addressing the justness and reasonableness of the reserve markets when the complaint, first and foremost, regards pricing in the energy market. This alone is sufficient grounds for the Commission to reject the March 29th Filing.

PJM already has a capacity market to provide capacity scarcity rents. PJM's energy market does not require the pervasive scarcity pricing inherent in an extended downward sloping ORDC to produce efficient market outcomes or just and reasonable rates.

a. PJM energy and reserve prices are not too low.

PJM energy and reserve prices are not too low. When supply increases in a market without a corresponding increase in demand, prices fall. For June 2019, PJM's reserve margin is 25.9 percent, 9.9 percentage points and 61.9 percent greater than the required 16.0 percent reserve margin.[7] PJM will have excess reserves of almost 13 GW on June 1, 2019, based on current positions. Announced retirements of 13 GW and another 15 GW of units at

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5 Hogan and Pope Affidavit at 9.

6 Hogan, William, MARKETS AND ELECTRICITY RESTRUCTURING: SCARCITY PRICING AND OPERATING RESERVES, API 166 (October 23, 2017).

7 Monitoring Analytics, *2019 Quarterly State of the Market Report for PJM: January through March* Vol. 2, Section 5: Capacity Market, Table 5-7.

risk signal future capacity exiting the PJM market.[8] Based on historical completion rates, 34.2 GW of new generation in the queue are expected to go into service. Market prices will fluctuate as these generators enter and exit. When the reserve margin is high, as it is currently, efficient prices are lower.

PJM's role is to operate a market that facilitates the competitive entry and exit of resources by allowing prices to rise and fall. Imposing a pricing construct like the extended downward sloping ORDC to administratively raise energy market prices is not consistent with independent, unbiased facilitation of the markets. Market forces will cause prices to appropriately adjust competitively. All else equal, anticipated resource retirements will raise energy prices. It is not necessary, efficient, or just and reasonable for PJM to administratively intervene in energy market pricing.

b. Energy market prices appropriately rise and fall with input prices.

Calls from generators for PJM to intervene in the markets to administratively raise prices began at the close of calendar year 2016, which saw the lowest energy prices in PJM history. The low energy prices in 2016 reflected low fuel prices. That is an efficient market outcome produced by a well functioning market. It is not the sign of a market design flaw. Figure 1 shows historic PJM monthly and annual load-weighted average LMP.

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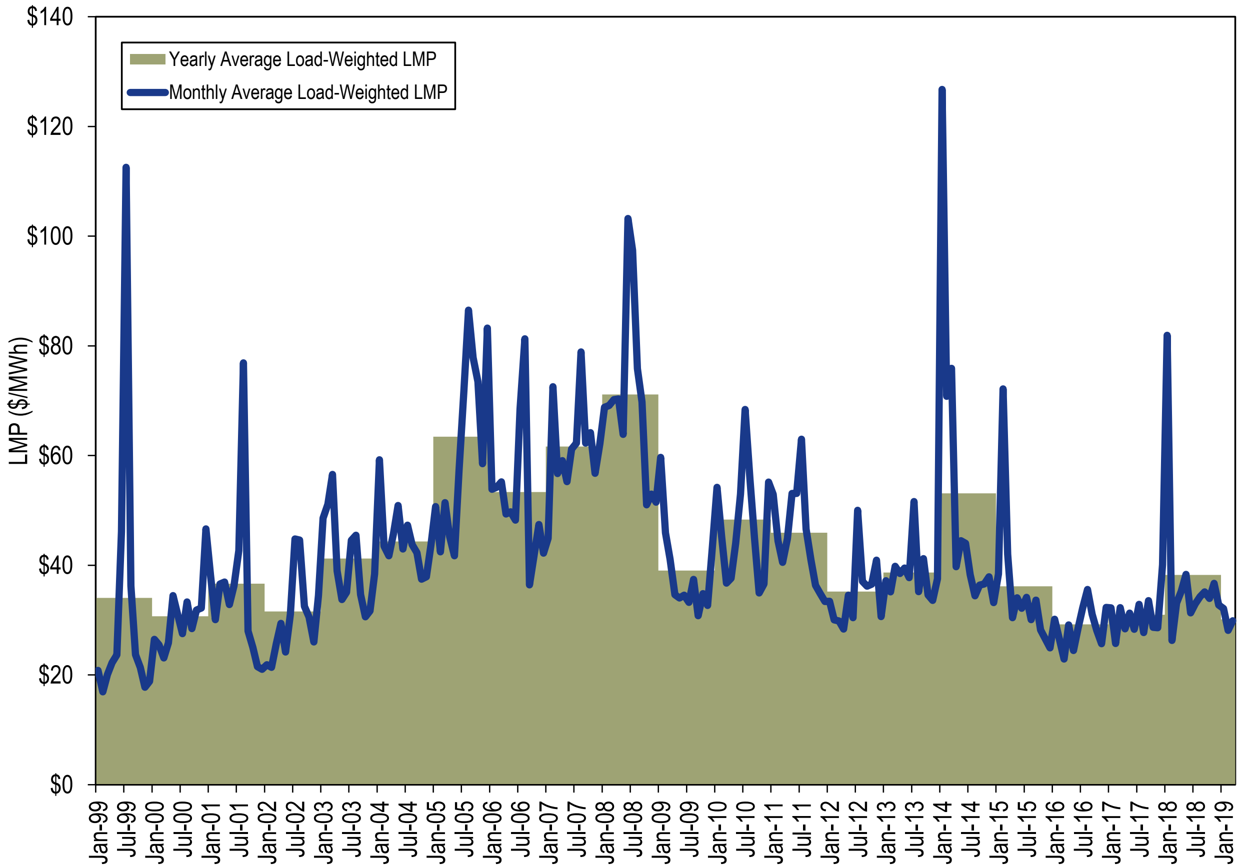
[8] Monitoring Analytics, *2019 Quarterly State of the Market Report for PJM: January through March* Vol. 2, Section 5: Capacity Market, Table 5-7.

Figure 1 Historic PJM Monthly LMP: January 1999 through March 2019



PJM claims that prices in January 2019 were too low. Some days in January 2019 were extremely cold in the PJM footprint. Cold weather does not by definition imply that the PJM system was "most stressed."[9] PJM supply was readily available, despite elevated natural gas fuel prices. Generator outage rates were low, natural gas prices remained below the cost of fuel oil, and reserves were plentiful, as a number of generators scheduled their capacity beyond PJM's dispatch instructions. The Market Monitor provides a report, assessing the functioning of the market during January 2019 as Attachment A. The report describes the changes in reserve levels during the day of January 31, 2019. PJM provides no explanation for why low reserve prices did not make sense on that day, when generators

9 *See* March 29th Filing at 20.

came online prior to their commitment periods to prepare for the winter peak that morning.[10] Natural gas prices rose above average levels. Uplift correspondingly rose to higher, but unremarkable levels. PJM provides no evidence of the operator actions that it claims led to increased uplift on January 21, 22, 30, and 31.

c. Shortage pricing provides efficient price signals when reserves are short.

An important aspect of efficient, just and reasonable, energy market prices is shortage pricing. PJM made important improvements to its tariff in response to Commission Order No. 825, providing consistency and transparency in shortage pricing.[11] Shortage pricing results in an administrative adder to the energy market price during reserve shortages. The administrative adder is equal to the shadow price of the reserve requirement constraint in the market clearing software. In other words, LMP increases by the administratively assigned cost of violating the minimum reserve requirement to serve load. Shortage pricing during a reserve shortage is important, sending a strong price signal when reliability issues arise. Shortage, or scarcity, pricing is unnecessary in the absence of shortages.

Shortage pricing is just and reasonable, supporting market efficiency, but the Market Monitor has identified opportunities for improvement in the implementation of shortage pricing, which are current under consideration by PJM stakeholders, that would likely increase the frequency with which actual shortage conditions are reflected in PJM's energy market prices.[12] [13] For example, from January 30 to February 1, 2019, PJM's real-time

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10 March 29th Filing at 20–21.

11 PJM Operating Agreement, Section 2.2(d)(ii).

12 *See* Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at 203-206.

13 *See* Monitoring Analytics, "Problem Statement / Issue Charge: Five Minute Dispatch and Pricing," presented to the PJM Markets Implementation Committee (April 10, 2019),

security constrained economic dispatch software (RT SCED) produced at least one solution with a shortage of reserves for 20 five minute intervals. RT SCED calculated multiple solutions with shortages for 10 five minute intervals. PJM priced only two intervals of shortage. Greater transparency around the pricing process and less operator intervention in the selection of RT SCED cases may have led to more shortage pricing intervals on these days when PJM's winter peak occurred. In fact, the frequency of shortage pricing intervals has increased since PJM and the Market Monitor began focusing more on the RT SCED approval process in winter of 2018/2019.[14]

The aim is pricing that supports market efficiency, not low pricing for the sake of low pricing. Shortage pricing, even for transient shortages, is efficient. The Operating Reserve Demand Curve defines the conditions when shortage or scarcity pricing occurs.[15] PJM's current ORDC represents actual reserve requirements, with the exception of the additional small 190 MW step. Shortage pricing according to an ORDC that represents actual reserve requirements is objective, transparent, and efficient for the market. An ORDC representing actual requirements is just and reasonable and is the standard for all the

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<http://www.monitoringanalytics.com/reports/Presentations/2019/IMM_MIC_RT_SCED_Problem_Statement_20190410.pdf>.

14 In 2018, PJM operators approved a total of three RT SCED cases with shortage (0.04 percent of all solved RT SCED cases with shortage) to calculate real time prices in LPC. In the first three months of 2019, PJM operators approved 13 RT SCED cases with shortage (1.1 percent of all solved RT SCED cases with shortage) to calculate real-time prices in LPC. *See* Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at 205; *2019 Quarterly State of the Market Report for PJM: January through March*, Vol. 2, Section 3: Energy Market at 210.

15 The Market Monitor distinguishes between scarcity pricing and shortage pricing. PJM's current market design contains shortage pricing, including the shadow price of the reserve constraint in the LMP only when serving load requires not meeting a reserve requirement. PJM's proposed market design can no longer be called shortage pricing, because it includes the shadow price of the reserve constraint in LMP when reserves are not short. Therefore, we refer to it more broadly as scarcity pricing.

RTOs/ISOs.[16] PJM is no exception. PJM cannot demonstrate that the shape of its current ORDC is not just and reasonable.[17]

2. PJM's Arguments that the Reserve Markets Are Not Just and Reasonable are Unsupported and Overstated.

a. The value of reserves depends on supply and demand conditions and reserve requirements.

PJM claims that reserves have inherent value, regardless of supply and demand conditions. PJM states (at 7) that "[c]urrent reserve market clearing prices – zero in about 60 percent of all hours for Synchronized reserve and in about 98 percent of all hours of Non-Synchronized Reserve – do not reflect the operational value of resource flexibility."[18] PJM confuses its operational need for reserves with efficient market prices. PJM's need to maintain reserves does not necessitate that reserve prices exceed zero at all times, or even the majority of the time. PJM's assertion is not based on economic fundamentals.

Customers place a high value on energy, but if the marginal cost of the marginal unit is zero, the efficient energy price is zero. The same holds for reserves. Regardless of the operational value of the product, supply and demand conditions determine the efficient market price. PJM's reserve markets do not produce prices equal to zero unless the quantity of zero cost reserves exceeds the reserve requirement. Zero cost reserves often exceed the reserve requirement because some generating units are inflexible and must be scheduled for hours ahead of and beyond the time at which they are needed to produce energy.

Figure 2 presents a stylized illustration of the daily pattern of PJM load, reserve requirements, and online capacity. Excess online capacity that is not providing energy,

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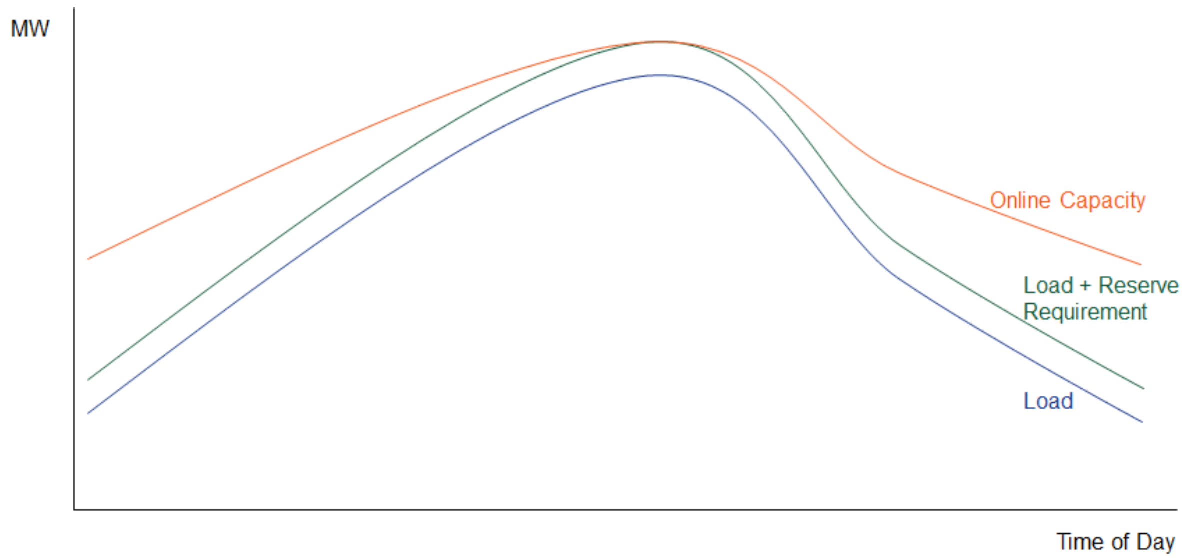
16 *See* MidContinent ISO, OATT, Schedule 28, Demand Curves for Operating Reserve, Regulating and Spinning; California ISO, OATT, Section 27.1.2.3; Southwest Power Pool, Integrated Marketplace Protocols, v.65.a, Section 4.1.5.2; and New York ISO, Manual 2: Ancillary Services, Section 6.8.

17 March 29th Filing at 7–8.

18 March 29th Filing at 7.

provides synchronized reserves. In Figure 2, the difference between the online capacity and the load plus reserve requirement is zero cost synchronized reserve. Figure 2 shows that reserves exceed the requirement during most hours of the day. Coal and combined cycle gas units comprise most of PJM's excess online capacity that is not providing energy at full output levels. Both have inflexibility in starting and shutting down, but provide a relatively large range of dispatchable capacity once online. Both coal and combined cycle units offer half their capacity as dispatchable.[19] Coal provides 28.6 percent of PJM's energy output, and combined cycle gas provides another 30.9 percent.[20] Thus, 60 percent of PJM's energy is provided by resources that create large quantities of zero cost synchronized reserves.

Figure 2 Stylized daily reserve pattern with inflexible units



A frequent price of zero for a reserve product is an efficient market outcome, because it is consistent with supply and demand conditions. Frequent reserve pricing at

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19 *See* Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at Tables 3-11 and 3-12. The total percent of offered capacity that is dispatchable for CC gas units is 49.6 percent. The total percent of capacity that is dispatchable for steam coal units is 47.3 percent.

20 *See* Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at Table 3-9.

zero is just and reasonable because it is an efficient, competitive outcome. This market design and market outcome is common among the RTOs. Finding it unjust and unreasonable in the PJM market would naturally extend to the other RTO markets.

b. An extended downward sloping ORDC is not required for market efficiency.

PJM argues that its ORDC is unjust and unreasonable simply because it is vertical.[21] Stating that an aspect of the market is unjust and unreasonable for the sole reason that it does not conform to PJM's preference for a sloped ORDC is not a sufficient argument for finding a vertical ORDC unjust and unreasonable.

PJM misidentifies the vertical nature of the ORDC as the aspect of the market preventing PJM from scheduling additional reserves. PJM states repeatedly (at 36, 37, and 38) that the vertical nature of the ORDC prohibits it from scheduling flexible capacity as reserves. This is not correct. A vertical ORDC is consistent with scheduling more reserves under a market design where PJM can update the reserve requirement when it needs additional flexibility. In fact, this is the method currently used by PJM to procure additional Day-Ahead Scheduling Reserves. Figure 3 depicts an expansion of a vertical ORDC to procure additional reserves. It shows that a vertical ORDC is consistent with procuring additional reserves. A vertical ORDC can shift as a result of operator actions to procure additional reserves based on operator uncertainty, inaccurate forecasts, or conservative operations. All of PJM's concerns about operational uncertainties can be managed in a market with a vertical ORDC.

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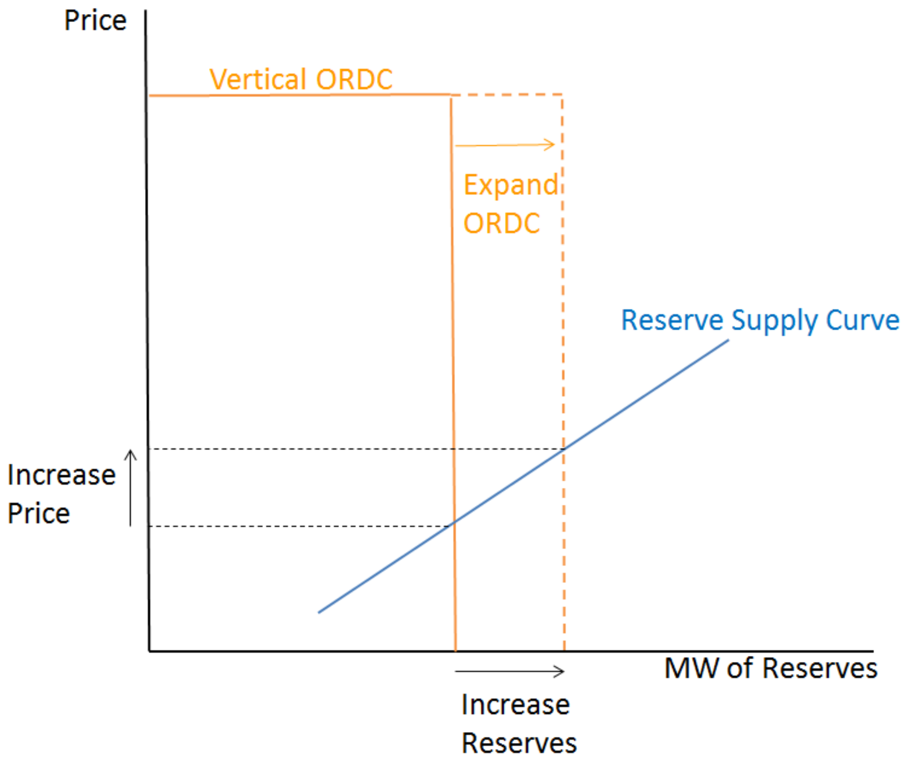
21 March 29th Filing at 36–38.

Figure 3 Expansion of a vertical ORDC to schedule additional reserves



The March 29th Filing points to the capacity market demand curve as support for the assertion that the existing vertical ORDC is unjust and unreasonable.[22] The fact that the capacity market Variable Resource Requirement (VRR) demand curve slopes downward does not make the vertical ORDC unjust and unreasonable. It is especially ironic that PJM points to the capacity market demand curve as a rationale for the ORDC when the March 29th Filing explicitly ignores the tight relationship between the energy market design and the capacity market design and specifically ignores the impact of the significant proposed increase in energy and ancillary revenues on the shape and location of the VRR curve. PJM does not have a theoretical basis for its ORDC. PJM has relied on vague references to value in providing a rationale for purchasing up to twice as many reserves as actually required, without explaining how the asserted value relates to the economic fundamentals. PJM in

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22 March 29th Filing at 37–38.

addition suggests that the VRR curve in the capacity market provides a justification for its downward sloping ORDC. PJM is not correct. The VRR curve shape reduces costs to customers as a result of reducing risk to investors. The VRR curve is not based on VOLL but is based on the cost of new capacity, the reference unit. The rationale for the downward sloping VRR curve, to the right of the target level of capacity, is to reduce risk to investors in capacity, to reduce the cost of capacity to investors and to reduce the costs of capacity to customers.[23] The VRR curve is designed to provide incentives to investors in capacity to provide the target level of capacity at the lowest cost through the operation of the capacity market. The rationale for the ORDC does not have the same basis. PJM also fails to recognize the dramatic difference in the relationship between the excess reserves that the March 29th Filing proposes to purchase and the reserve requirement; and the relationship between the downward sloping portion of the VRR curve and the target level of capacity. The downward sloping portion of the VRR curve is about five percent more MW than the target reserve margin MW on the VRR curve. The downward sloping portion of the ORDC is about 100 percent more MW than the reserve requirement.

c. Uplift results do not indicate a market design flaw.

In an attempt to support a finding that the energy and reserve markets are unjust and unreasonable, PJM argues that operator actions to procure additional reserves with a vertical ORDC may increase uplift.[24] PJM provides no evidence directly linking operator actions or the shape of the ORDC to actual uplift data. PJM uplift is low, accounting for $0.23 per MWh of energy or 0.4 percent of LMP.[25] The bulk of uplift is driven by specific

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23 For a good statement of the theory underlying VRR curves and their shape, see: Stoft, Steven E., Prepared Direct Testimony on behalf of ISO New England, Inc., Docket No. ER03-563-03 (August 31, 2004).

24 *See* March 29th Filing at 13–14, 21–23, 30–37.

25 Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 1: Introduction at Table 1-8.

issues with units or specific local transmission system conditions, such as local reliability issues, extremely inflexible parameters, or failure to follow dispatch instructions. PJM could better reduce uplift through uplift eligibility and calculation rules, rather than changing energy and reserve market price formation. The lack of evidence directly linking operator actions, reserve market outcomes, or the ORDC shape to quantifiable levels of uplift invalidate PJM's arguments that the energy and reserve markets are unjust and unreasonable due to uplift effects.

PJM states (at 21) that "[o]ut-of-market actions by PJM dispatchers to ensure reserves during these stressed conditions led to a spike in uplift."[26] PJM provides no evidence of a causal relationship between reserves and uplift in January 2019. Daily uplift costs rose proportional to natural gas prices. The total uplift for January 2019, at $7.9 million, was less than the monthly average uplift for 2018 and for 2017, which were $16.5 million and $10.6 million per month.[27] [28] Attachment A provides further details regarding daily uplift for January 2019. Overall, uplift in January 2019 was unremarkable and does not support PJM's arguments that the energy and reserve markets are unjust and unreasonable.

d. *Future penetration of renewable energy does not make current reserve prices unjust and unreasonable.*

PJM argues that an increased need for flexibility due to projected increases in intermittent, renewable resources supports its arguments that energy and reserve prices are unjust and unreasonable.[29] Projected intermittent resource penetration does not justify a

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26 March 29th Filing at 21.

27 Attachment A: Winter Report at 25.

28 Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 4: Energy Uplift at Table 4-1.

29 March 29th Filing at 7–8.

finding that the current market is unjust and unreasonable. Other RTO markets with similar reserve products and without extended downward sloping ORDCs accommodate serving up to 70 percent of load with intermittent resources.[30] PJM makes no claim that it has less flexibility available than the other RTOs. In fact, PJM leads the nation in building the most advanced, flexible new combined cycle resources. PJM has over 40 GW of new combined cycle capacity.[31] PJM provides no evidence that its current market is unprepared for the integration of more intermittent resources.

PJM argues that it differs from the MidContinent Independent System Operator, Inc. (MISO) and Southwest Power Pool, Inc. (SPP) in that the PJM states do not rely on cost of service regulation to support the market.[32] This, PJM argues, calls for the Commission to evaluate PJM's energy and reserve markets differently by finding the aspects of the energy and reserve markets that are common among the RTOs unjust and unreasonable for PJM, but not for the other RTOs. However, the Commission has rejected similar arguments in other proceedings.[33] Efficient energy and reserve market pricing does not differ based on whether the RTO relies on a capacity market or cost of service regulation.

e. Ample capacity responds to spinning reserve events.

In the March 29th Filing, PJM mischaracterizes the response to spinning events. PJM relies heavily on the argument that the response rate of the estimated Tier 1 synchronized reserve capacity is less than the assigned Tier 2 capacity.[34] PJM calculates the Tier 1

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30 *See* MidContinent ISO, OATT, Schedule 28, Demand Curves for Operating Reserve, Regulating and Spinning; California ISO, OATT, Section 27.1.2.3; and Southwest Power Pool, Integrated Marketplace Protocols, v.65.a, Section 4.1.5.2.

31 Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 12: Generation and Transmission Planning at Table 12-13.

32 March 29th Filing at 8.

33 *See* 167 FERC ¶ 61,030 at P 46.

34 March 29th Filing at 18–19 and Pilong Affidavit at 8.

response rate based on its estimate of Tier 1 using the market software (RT SCED), which incorporates PJM's deselection of units and modifications of units' physical parameters, especially ramp rates.[35] But PJM pays Tier 1 resources based on a different number, the actual metered response to the spinning event. Table 1 shows the response of Tier 1 and Tier 2 synchronized reserve to spinning events, including the settled Tier 1 response that is paid for actually responding. Table 1 shows that PJM resources provide greater response to spinning events than PJM calculates, for which PJM compensates them at a rate of $50 per MWh. Frequently the response exceeds PJM's Tier 1 estimate. Arguments in the March 29th Filing that Tier 1 response rates demonstrate a lack of response to spinning events are not accurate. PJM's arguments do not provide evidence that the synchronized reserve market is unjust and unreasonable.

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35 *Id.*

Table 1 Tier 1 and Tier 2 Synchronized Reserve Event Response: April 2018 through March 2019

Event Date	Event Cause	Start Time	Duration (Min)	Tier 1 Estimate MW	Tier 1 Response MW	Settled Tier 1 MW Increase	Tier 2 Assigned MW
12-Apr-18	Unit Trip	13:28	10	1,063.3	591.2	1,633.0	464.6
4-Jun-18	Unit Trip	10:22	6	1,584.5	533.6	1,324.1	58.0
29-Jun-18	Unit Trip	15:21	9	1,425.8	1,135.6	3,116.7	167.4
30-Jun-18	Unit Trip	9:46	11	2,710.1	2,086.2	3,993.8	71.6
4-Jul-18	Unit Trip	10:56	6	1,202.1	580.7	2,572.8	279.2
10-Jul-18	Low ACE	15:45	13	784.3	524.9	2,219.1	494.6
23-Jul-18	Unit Trip	9:02	8	1,087.9	875.5	2,767.3	427.6
23-Jul-18	Unit Trip	15:43	6	635.6	342.6	1,464.0	425.6
24-Jul-18	Unit Trip	16:17	7	666.4	268.9	2,314.0	794.6
12-Aug-18	Unit Trip	11:06	11	1,824.5	1,390.4	2,987.9	274.5
13-Sep-18	Unit Trip	9:54	7	1,435.9	695.0	1,691.5	460.6
14-Sep-18	Unit Trip	13:24	7	1,908.9	731.0	2,144.8	258.5
26-Sep-18	Unit Trip	20:28	8	800.2	241.9	1,181.0	674.6
30-Sep-18	Unit Trip	11:29	11	1,430.9	976.4	2,355.9	231.2
30-Oct-18	Unit Trip	6:40	11	239.7	215.9	815.9	607.7
22-Jan-19	Unit trip	22:30	8	2,421.1	875.0	1,967.3	14.4
31-Jan-19	Unit trip	1:26	5	1,139.5	561.7	1,498.1	715.5
31-Jan-19	Unit trip	9:26	8	1,609.8	541.5	2,383.4	325.8
25-Feb-19	Unit Trip	0:26	8	2,158.2	729.4	1,522.3	362.5
3-Mar-19	Unit Trip	12:31	9	2,915.2	1,332.2	2,345.9	70.0
6-Mar-19	Unit Trip	22:06	9	1,874.2	811.9	1,691.2	738.1

f. PJM overstates the benefits of clearing 10 minute reserves in the 60 minute settlement Day-Ahead Market.

In arguing that the misalignment of day-ahead market and real-time market reserve clearing is unjust and unreasonable, PJM does not discuss the fact that the reserve products can never be fully aligned between the hourly day-ahead market and the five minute clearing real-time market.[36] Even if the day-ahead market could accurately predict the conditions in the real-time market, the time interval difference means that the day-ahead market does not capture all the intricacies of unit ramp rates and performance modelled in

[36] March 29th Filing at 41–42.

the real-time market. The same discrepancy affects energy clearing, but the impact is limited to the portion of energy cleared by units operating for all or part of the hour below their maximum output level.

All synchronized reserves clear on units operating below their maximum output level based on intrahour ramping capability. This means that the clearing of reserves is sensitive to the time interval difference between the day-ahead market and the real-time market. Misalignment between reserve products in the day-ahead market and the real-time market cannot be resolved. The benefits of modelling 10 minute reserves in an hourly day-ahead market are limited at best. PJM provides no evidence to support its claim that "PJM's current practice can result in higher costs to meet the 10-minute reserve requirements in real-time than would occur had those requirements been modeled in the day-ahead market."[37] PJM has not established that misalignment between reserve products in the day-ahead market and the real-time market is grounds for finding the reserve markets unjust and unreasonable.

B. PJM's Proposed Reforms to the Energy and Reserve Markets are Not Just and Reasonable.

The March 29th Filing proposes to introduce to PJM's markets an extended downward sloping Operating Reserve Demand Curves that requires customers to buy reserves beyond the defined minimum reserve requirements. These curves may extend indefinitely beyond the minimum reserve requirements. PJM's current calculations for its proposed ORDC define a positive marginal value for reserves up to nearly twice the current reserve requirements. However, the significance of the proposed ORDCs lies not in the width or height of the ORDCs but in their sloped shape. The sloped shape of the ORDCs means that the reserve requirements are never satisfied until the end of the ORDCs. When a reserve requirement is not satisfied, the market is scarce of that reserve product. In the

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37 March 29th Filing at 42.

mathematical formulation of prices, a sloped ORDC assigns to every MW of load served a cost associated with failure to satisfy the reserve requirement, adding a scarcity component to the energy price. With the lower priced portion of the ORDC at moderate prices, the market software makes an economic choice to maintain some level of scarcity. In maintaining that scarcity, the market would also maintain the scarcity pricing under normal operating conditions. Therefore, the extended sloped ORDCs create scarcity pricing all the time rather than when there is an actual shortage.

1. Charging a Scarcity Price to Load in the Absence of an Actual Shortage Is Inefficient and Is Not Just and Reasonable.

Scarcity pricing during actual operating reserve shortages, called shortage pricing, is an efficient aspect of the PJM market design. Shortage pricing sends a strong price signal to both supply and demand to resolve the shortage. When the market is not short, the vertical ORDC produces competitively determined prices for reserves, equal to the marginal cost of reserves, with no impact to energy prices.

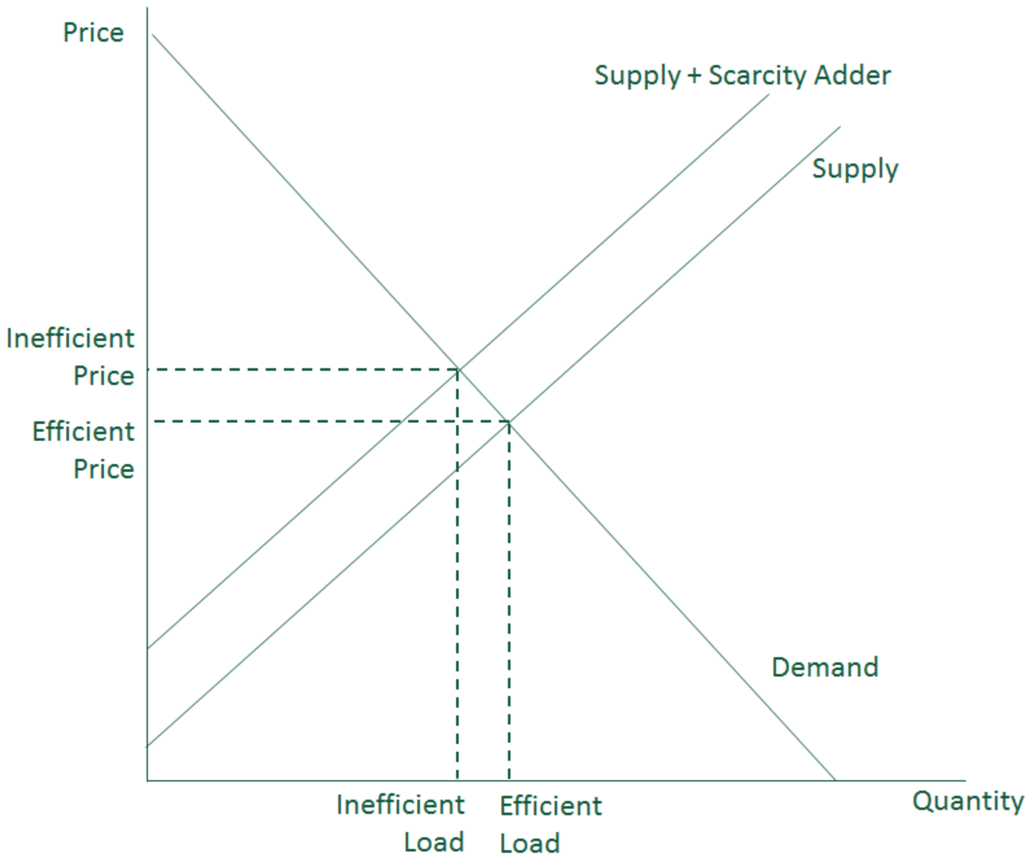
PJM proposes to charge all load an administratively determined scarcity price even when it carries reserves well in excess of the NERC defined reserve requirements and well in excess of the historic levels of reserves carried by PJM.[38] This proposed persistent scarcity pricing would send a price signal for load to curtail when the marginal value of energy to the consumer exceeds the marginal cost of producing that energy. The purpose of this load curtailment would be to create more reserves even though the system is operating under normal conditions with ample reserves. The long run investment signal to load is to leave the PJM system, because PJM's market indicates constant scarcity. The price signal says that PJM cannot serve load at the marginal cost of producing energy during any hour of the operating day for all days of the year. This is clearly not the case, at PJM's target reserve

[38] March 29th Filing at 102–103.

margin or at PJM's current 28.3 percent reserve margin.[39] It is an incorrect price signal that is not and cannot be just and reasonable.

Figure 4 shows how an efficient market price is determined where supply and demand curves intersect. With a scarcity adder to marginal cost, the price is inefficient. If demand is responsive to price, which is the case in the long run and increasingly also in the short run, customers will inefficiently reduce load.

Figure 4 Efficient price and inefficient scarcity price when reserves are not short

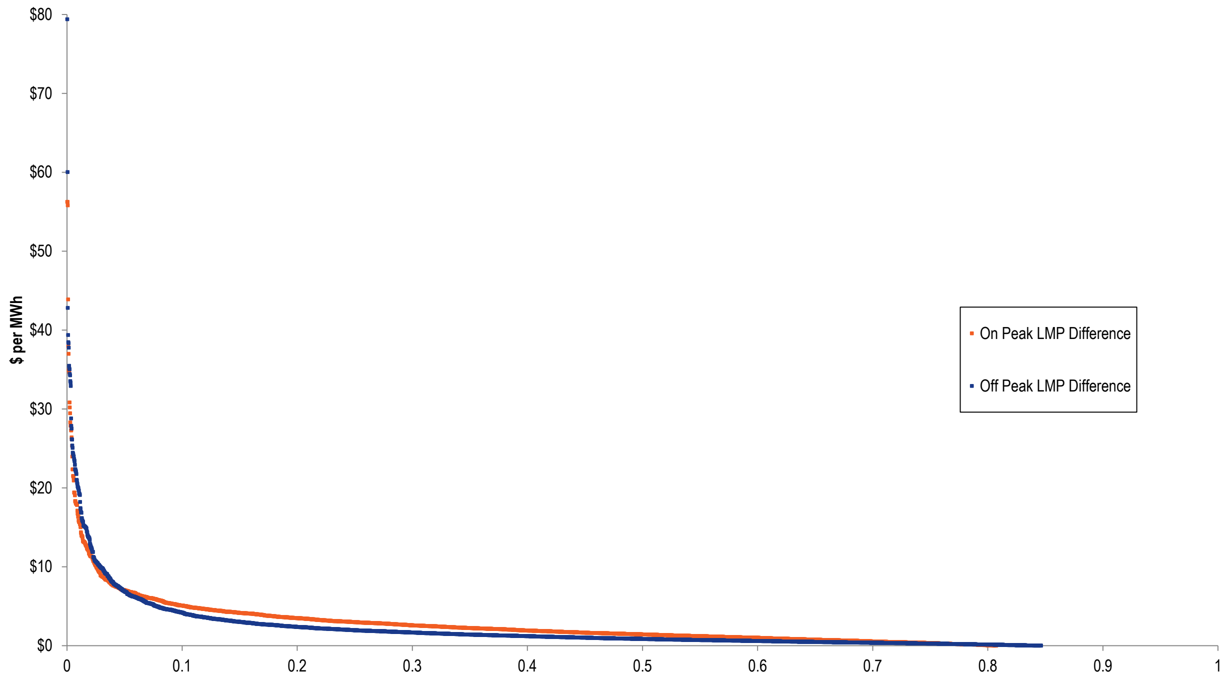


The simulation results show that PJM's proposed ORDCs raise LMP in 85 percent of hours of the year. The highest price increases are in off peak, not on peak hours. Figure 5 shows the ranked price increases from simulation Case A, the base case, to simulation Case

39 *See* Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market at Table 5-7.

C, the ORDC case. It demonstrates the large effect of the ORDC on LMP. The effects are not targeted to the limited hours when the market is "stressed."[40]

Figure 5 Ranked Simulated Energy Price increases, Case A to Case C



a. PJM understates the impact of its proposal on prices and revenues.

The Market Monitor estimates that the increase in the average annual energy market price that would result from PJM's proposed ORDC is $1.12 to $1.96 per MWh.[41] This exceeds the $0.46 per MWh change in LMP claimed by PJM. PJM also finds the $1.96 per MWh increase in LMP, but argues that $1.50 per MWh is due to the economic recommitment of resources, which PJM models in simulation Case B, rather than to the ORDC.[42] However, Case B is part of PJM's proposal. PJM's proposal has the market commit additional generation under the ORDC instead of operators choosing resources that may

40 March 29th Filing at 20.

41 Attachment B: Simulation Results at Table 1.

42 March 29th Filing at Keech Affidavit at para. 39.

not be part of the economic solution.[43] PJM also proposes to incorporate the reserve clearing in the day-ahead market, which PJM argues is the purpose of Case B.[44] [45] Case B uses the same status quo ORDCs as Case A and it optimizes the commitment of steam units, which is a function of the day-ahead market. The relevant comparison of PJM's proposal is Case A, the closest to the status quo, to Case C, with the ORDC and economic recommitment of resources. Further details are included in Attachment B.

The Market Monitor replicated PJM's simulations using identical software and the same input data as PJM. Replication allows the Market Monitor to verify the results, understand the modelling assumptions, analyze the results in greater detail, and perform alternative simulation scenarios. The details of the Market Monitor's simulations are included in Attachment B: ORDC Simulation Results.

b. PJM's proposed ORDC is unprecedented and diverges from theoretical approaches.

Other RTOs have ORDCs with slopes or levelled steps, but only for pricing during actual shortages. In fact, the MidContinent ISO (MISO) incorporates slopes, steps, and the product of the probability of a loss of load and an estimate of the Value of Lost Load (VOLL) in its Contingency Reserve Demand Curve for pricing shortages.[46] The MISO Market Monitor recommends changes to MISO's ORDC for pricing shortages.[47] California ISO, Southwest Power Pool, and New York ISO use stepped ORDCs for shortage pricing

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43 March 29th Filing at 55.

44 March 29th Filing at 74.

45 March 29th Filing at Keech Affidavit at para. 39.

46 MidContinent ISO, OATT, Schedule 28, Demand Curves for Operating Reserve, Regulating and Spinning, <https://cdn.misoenergy.org/Schedule%2028109698.pdf>, accessed May 13, 2019.

47 Potomac Economics, *2017 State of the Market Report for MISO*, Appendix: Real-Time Market Performance at 59–63.

only.[48] [49] [50] Unlike PJM's proposed ORDC, an ORDC with a slope or steps for varying levels of shortage, like those used by the other RTOs, applies no administrative scarcity component to energy or reserve prices under normal operating conditions. PJM's proposal is unlike those used for the other FERC jurisdictional RTOs. Finding PJM's markets unjust and unreasonable so that such a curve can be implemented would also implicate the other RTOs' markets. PJM's proposal is unprecedented. There is no market design employed by the other RTOs that supports finding PJM's proposed ORDCs just and reasonable.

The March 29th Filing proposes administrative, rather than competitive, pricing for its energy market. PJM's proposed ORDCs administratively set prices for reserves and energy at PJM's subjective ORDC value in nearly all market intervals with no shortage conditions. The proposed ORDCs allow PJM to administratively alter rates by changing the inputs to and details of the ORDC calculation. The proposal is unprecedented among FERC jurisdictional RTOs. Only the Electric Reliability Council of Texas (ERCOT) uses such an ORDC, and ERCOT does so with the express purpose of raising energy prices above marginal cost as an alternative to a capacity market. As described by Hogan and Pope, in developing the ORDC, "ERCOT reconsidered the treatment of operating reserves, rather than creation of a capacity market, to address the missing money arising from energy-only pricing."[51] ERCOT essentially layers an administrative capacity demand curve, targeting the capacity reserve margin, on top of marginal cost energy market pricing.[52] PJM proposes

48 California ISO, OATT, Section 27.1.2.3.

49 Southwest Power Pool, Integrated Marketplace Protocols, v.65.a, Section 4.1.5.2.

50 New York ISO, Manual 2: Ancillary Services, Section 6.8.

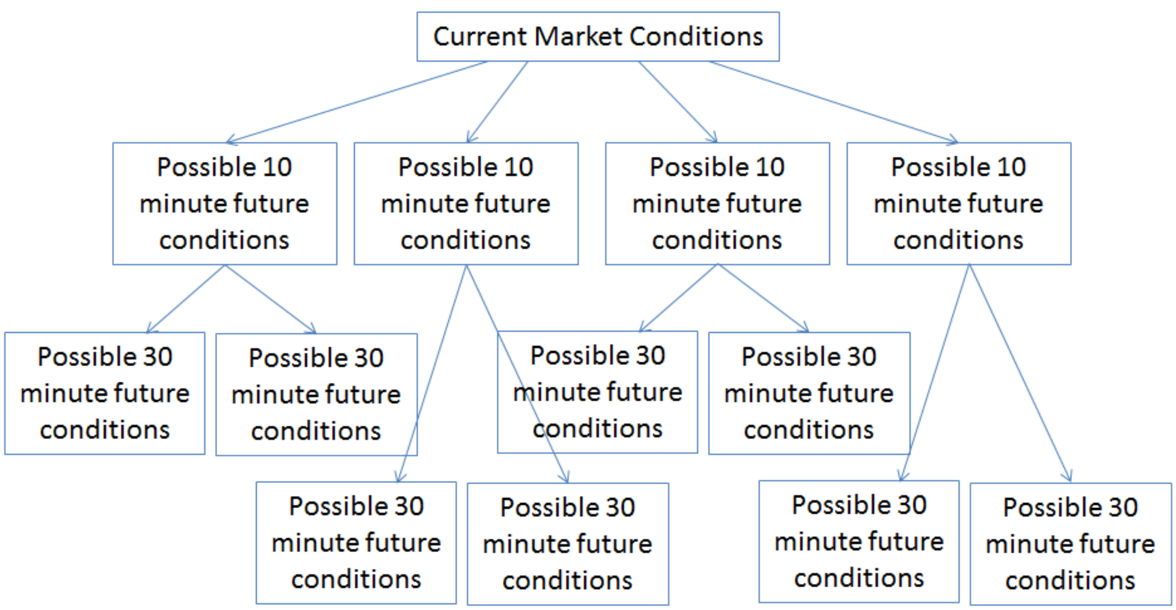
51 Hogan, William W. and Susan L. Pope, *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT*, FTI Consulting (May 2017).

52 *See*, *e.g.*, Kleckner, Tom, "Texas PUC Responds to Shrinking Reserve Margin," RTO Insider (January 18, 2019), <https://www.rtoinsider.com/ercot-puct-reserve-margin-109500/>, accessed May 13, 2019.

to have both the administrative ORDC in the energy market and the capacity market with its own demand curve based on the capacity reserve margin. The proposal to include scarcity rents in the energy market under normal operating conditions without an offset for the collection of the same scarcity rents through the capacity market is not just and reasonable. Inclusion of an offset would remove one but not all the fatal flaws incorporated in the March 29th Filing.

There is no theoretical basis for PJM's ORDCs. Hogan and Pope explain that "the need for operating reserves arises from the uncertain future supply and demand conditions" and describe a stochastic model with many expected future possible conditions.[53] Figure 6 provides a simple depiction of how a stochastic model branches into future possible market conditions each with a different probability of occurring. A model considering 10 and 30 minute reserves would include, at least, all possible 10 and 30 minute market conditions.

Figure 6 Current and Possible Future Market Conditions in a Stochastic Model



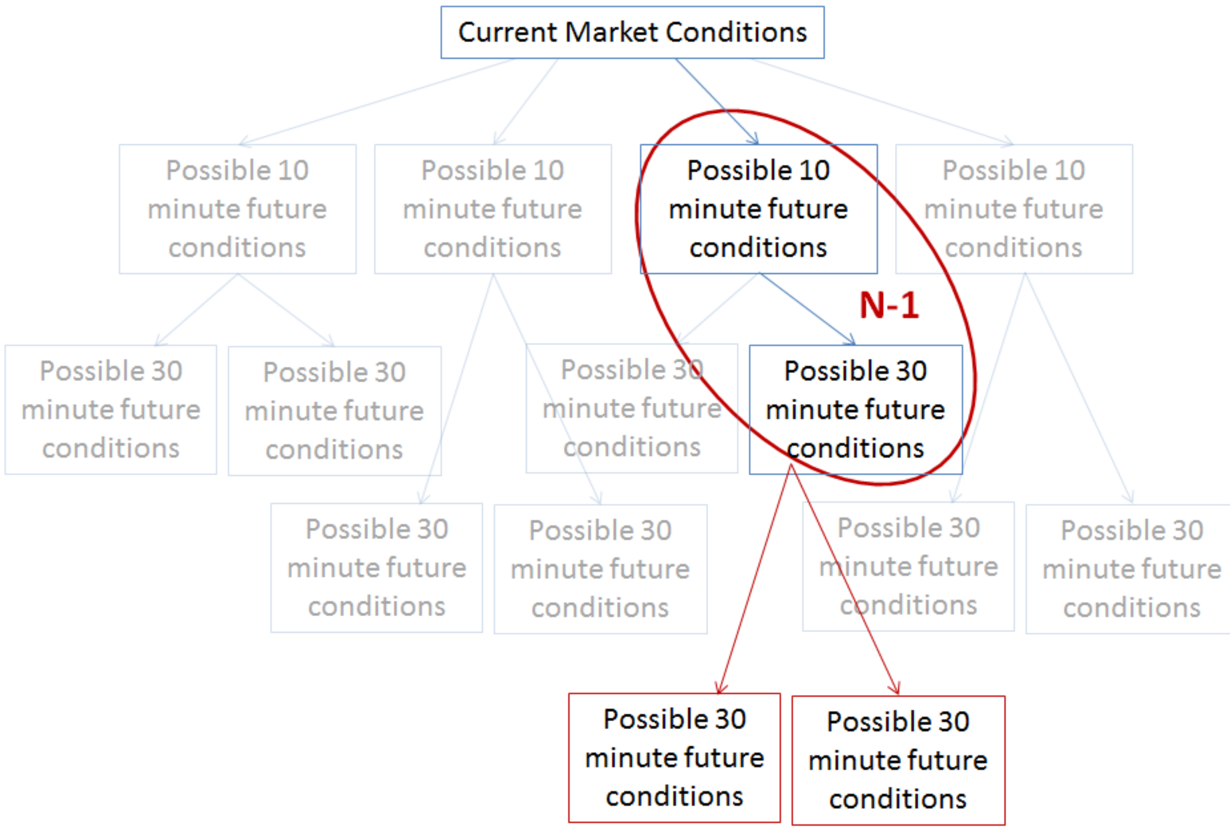
53 March 29th Filing, Hogan and Pope Report at 13.

Hogan and Pope explain that the chosen solution to the complexity of the stochastic model has been to focus on one conservative future condition, the N-1 condition.[54] Hogan and Pope state that "the compromise has long been to take the conservative position to protect simultaneously against one of these events occurring (the well-known "N-1" condition), without accounting for the complete joint probabilities of one or more contingencies at the same time."[55] PJM's proposed ORDC confounds the N-1 condition with the stochastic model described by Hogan and Pope. PJM starts with the N-1 condition reserve requirements and models uncertainty on top of the N-1 condition. Figure 7 depicts the chosen N-1 market condition and the additional uncertainty that PJM models in expanding the ORDC from the N-1 reserve requirement. PJM's approach does not follow the stochastic model approach that serves as a basis for Hogan and Pope's theoretical ORDC or the standard N-1 contingency model.

54 *Id.*

55 *Id.*

Figure 7 PJM's Overly Conservative N-1 Plus Uncertainty Model



Hogan and Pope suggest an approach where "an ORDC arises to proxy for the absence of demand bidding…"[56] PJM does not use an approach that considers consumers' willingness to pay for reserves. In fact, PJM's ORDCs would price reserves and energy with an implied value of lost load higher than the $9,000 per MWh value used in the Electric Reliability Council of Texas's (ERCOT's) energy only market. In the Summer of 2017, ERCOT priced reserves at $50 to $225 per MWh for 4,000 MW of reserves for the afternoon peak hours.[57] The loss of load probabilities consistent with these prices are 0.6 to 2.5

56 March 29th Filing, Hogan and Pope Report at 14.

57 ERCOT, Scarcity Pricing using ORDC for reserves and Pricing Run for Out-Of-Market Actions, presentation to the PJM Energy Price Formation Senior Task Force (March 29, 2018) at 38, <https://pjm.com/-/media/committees-groups/task-forces/epfstf/20180329/20180329-item-07-scarcity-pricing-using-ordc-for-reserves-and-pricing-run-for-out-of-market-actions-ercot.ashx>. The loss of load probability varies based on the proportion of reserves that are offline or online.

percent, obtained by dividing the ERCOT reserve price by the $9,000 per MWh VOLL. The ERCOT loss of load probabilities provide a basis for comparing the loss of load model to the PJM model.

By applying the loss of load probabilities at 4,000 MW to the PJM ORDCs, one can calculate the VOLL implied by PJM's ORDC prices. The implied PJM VOLL is equal to PJM's proposed secondary reserve ORDC price divided by the loss of load probability.[58] The PJM ORDC price for secondary reserves for summer time afternoon peak hours, time block 5, is $248.40 per MWh at 4,000 MW of reserves. PJM's ORDC price at 4,000 MW is higher than ERCOT's price at 4,000 MW. The implied PJM VOLL is $9,934 to $44,349 per MWh based on the proposed secondary reserve demand curve alone, using ERCOT's loss of load probabilities. PJM's loss of load probabilities are likely significantly lower than the ERCOT loss of load probabilities, given the large difference in reserve margins between PJM and ERCOT. As a result the implied PJM VOLL is significantly higher than the calculation based on ERCOT's loss of load probabilities. PJM would apply additional ORDC pricing based on the primary and synchronized reserve demand curves. ERCOT's ORDC is a combined demand curve for all reserve products. It tops out at $9,000 per MWh, and does not cascade across products to up to $12,000 per MWh, as PJM proposes.[59] [60] There is no theoretical basis for imposing PJM's proposed high energy prices on consumers. They are higher than in any other RTO. It is not just and reasonable.

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58 ERCOT's ORDC considers online and offline resources available for the next hour, so the relevant PJM proposed ORDC for comparison is the secondary reserve (30 minute) ORDC, which is met by the sum of synchronized, primary, and 30 minute reserves.

59 March 29th Filing at 12.

60 ERCOT, Scarcity Pricing using ORDC for reserves and Pricing Run for Out-Of-Market Actions, presentation to the PJM Energy Price Formation Senior Task Force (March 29, 2018), <https://pjm.com/-/media/committees-groups/task-forces/epfstf/20180329/20180329-item-07-scarcity-pricing-using-ordc-for-reserves-and-pricing-run-for-out-of-market-actions-ercot.ashx>.

PJM's proposed ORDC does not produce results similar to ERCOT's VOLL approach. Hogan and Pope provide calculations and produce results in Figure 10 of the appendix of their report attached to the March 29th Filing. The results appear to coincide closely with PJM's results. However, Hogan and Pope's calculations are not based on actual data to determine a loss of load probability or a minimum contingency level consistent with load shedding. The contrived example provides no evidence that PJM's proposal is similar to the VOLL approach described in Hogan and Pope's report. There is no evidence or claim in Hogan and Pope's report that PJM's actual proposal is just and reasonable.

2. PJM's Proposed $2,000 per MWh Penalty Factor Exceeds the Cost of Efficiently Dispatching Reserves.

PJM claims that the reserve penalty factor must be at least $2,000 per MWh because "PJM dispatchers *will* commit all generation… and will deploy pre-emergency and emergency load management reductions" to maintain the NERC defined reserve requirements.[61] PJM's arguments do not support its claim that the value must be at least $2,000 per MWh. The short run marginal cost of generation rarely exceeds the current $850 per MWh penalty factor and cannot exceed $1,000 per MWh without prior PJM approval of cost-based offers. It is only under rare and foreseeable circumstances that PJM may need to raise the value above $1,000 per MWh. PJM does not deploy pre-emergency or emergency demand response prior to synchronized or primary reserve shortages. PJM has not deployed pre-emergency or emergency demand since April 22, 2015, but PJM has experienced shortages of reserves in the last four years. The maximum offer price, or strike price, for load management resources, $1,849 per MWh, is not a short run marginal cost. Requiring the reserve penalty factor to exceed the strike price is not necessary for efficient dispatch. The current maximum offer price for load management resources is designed to

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61 March 29th Filing at 48.

be greater than the reserve penalty factor.[62] The load management strike price is an artificial price designed to permit PJM to implement a crude form of scarcity pricing. PJM should eliminate the strike price and modify the treatment of load management in defining shortage. The proposed $2,000 per MWh penalty factor is an overstated value for the highest marginal cost resource on the system. Using it as the reserve penalty factor imposes unnecessary costs on customers, which is not just and reasonable.

3. There are a Number of Technical Issues with the Calculation of the ORDCs.

a. The forecast time frame for ten minute reserves is not 30 minutes. It is not greater than 15 minutes.

PJM claims that 10 minute reserves are procured for a time frame 30 minutes in the future.[63] This time frame is the basis for calculating the proposed synchronized and primary reserve ORDCs.[64] The relevant time frame depends only on the time frame in which the forecast uncertainty is resolved, which is the 10 to 14 minute time frame from when the forecasts go into the market software to when the forecasted load, generation, and reserves are realized.

PJM uses the Real-Time Security Constrained Economic Dispatch (RT SCED) tool to calculate energy and ancillary services dispatch MW for generation units. RT SCED uses a number of inputs, including load forecast data, generator offers, state estimator output, and outage data to economically dispatch the system for energy and ancillary services (primary reserves and synchronized reserves) for a target interval that is approximately 10 to 14

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62 OA Schedule 1 § 1.10.1A.

63 March 29th Filing at 56.

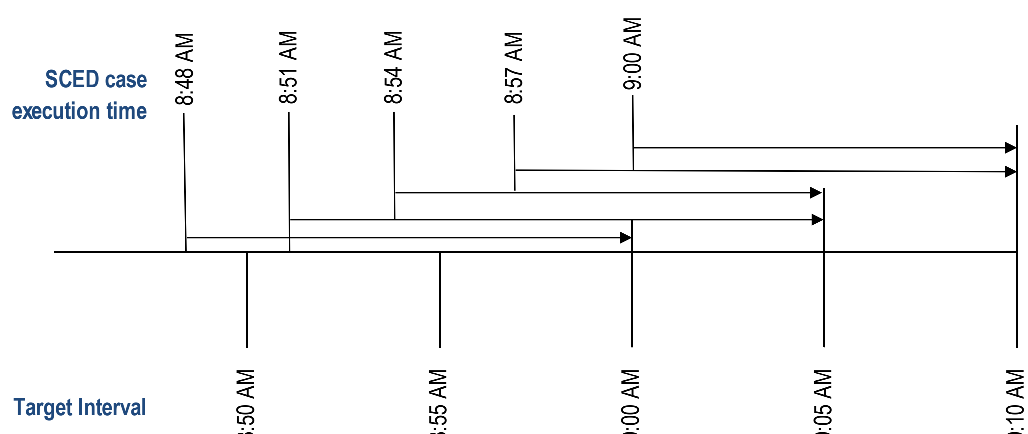
64 Rocha Garrido Affidavit at para. 13.

minutes in the future. The inputs used in RT SCED are forecast data for the target interval. PJM Manual 11 states:[65]

> The RT SCED cases use load forecast and other system information that are effective for the look-ahead interval, rather than the time at which the case is executing, to achieve a dispatch solution that will adequately control for those forecasted conditions.

RT SCED cases are executed approximately every three minutes. Each instance of RT SCED case execution includes three cases, with different levels of load bias in each, that solve for economic dispatch for a target interval that is 10 to 14 minutes ahead of the time that it is executed. Figure 8 shows an example timeline of RT SCED case execution times and the target interval that RT SCED case solves for. In the scenario shown in Figure 8, for the target interval at 9:00 AM, PJM executed three RT SCED cases at 8:48 AM, with a 12 minute look ahead time. For the target interval 9:05 AM, PJM executed three RT SCED cases at 8:51 AM (14 minute look ahead time) and three SCED cases at 8:54 AM (11 minute look ahead time). For the target interval at 9:10 AM, PJM executed three SCED cases at 8:57 AM (13 minute look ahead time) and three SCED cases at 9:00 AM (10 minute look ahead time).

Figure 8 SCED case execution time and the target intervals



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65 PJM "Manual 11: Energy and Ancillary Services Market Operations," § 2.5 Real-Time Market Applications, Rev. 104, (February 7, 2019) at 45.

The inputs used in the RT SCED solution for any given look ahead interval are generated from data that is available at the time that the RT SCED case is executed. This look ahead time is 10 to 14 minutes. All of the uncertainty is resolved in the 10 to 14 minutes from the solution time to the target dispatch interval. To conclude that the relevant look ahead period for evaluating forecast errors is 20 minutes, PJM sums the RT SCED forecast period (10 to 14 minutes) and the reserve contingency response period (10 minutes). PJM then rounds the value up to 30 minutes to use as the uncertainty time frame for calculating the ORDCs.

PJM has to operate to account for the load forecast, and any generator forced outages that may occur within the 10 to 14 minute period between the target interval and the time that an RT SCED case is executed. It is appropriate to use a 15 minute forecast error, and 15 minute forced outage rate to quantify this uncertainty. Using a 30 minute forecast error inflates the amount of relevant uncertainty. It is not just and reasonable to use a 30 minute forecast error to calculate 15 minute uncertainty, and to use that to procure additional reserves and set higher prices.

The Market Monitor recalculated the PJM synchronized and primary reserve ORDCs using 15 minute forecast error instead of 30 minute forecast error and estimated the impact of using PJM's ORDCs based on 15 minute forecasts. For each five minute market interval during the study period the Market Monitor obtained 15 minute forecast error data for load, wind generation, and solar generation from PJM.[66] The forecast error was computed as the difference between the forecast value made 15 minutes prior to the start of the market interval and the actual observed value at the start of the market interval. The Market Monitor computed for each five minute market interval during the study period, the actual forced outage MW that occurred within 15 minutes prior to the start of the market

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[66] The study period consists of 5 minute market intervals from January 1, 2015 through December 31, 2017.

interval.[67] The same method employed by PJM to develop the 30 minute ORDCs was then used to compute comparable 15 minute PJM ORDCs.[68] Figure 9 shows the impact of using a 30 minute look ahead period versus a 15 minute look ahead period. Moving left to right on the curves, the 30 minute ORDC steps down from $2,000 per MW to $552.179 per MW at the minimum reserve requirement. The 15 minute curve steps down from $2,000 per MW to $350.29 per MW at the minimum reserve requirement, a difference of $201.87 per MW. The point on the ORDC where the reserve level is equal to the minimum reserve requirement is defined in the tariff and operating agreement as Point (3). In Figure 9, the Point (3) price on the PJM ORDC (30 minute forecast) is 57.6 percent higher than the corresponding Point (3) price on the PJM ORDC (15 minute forecast).

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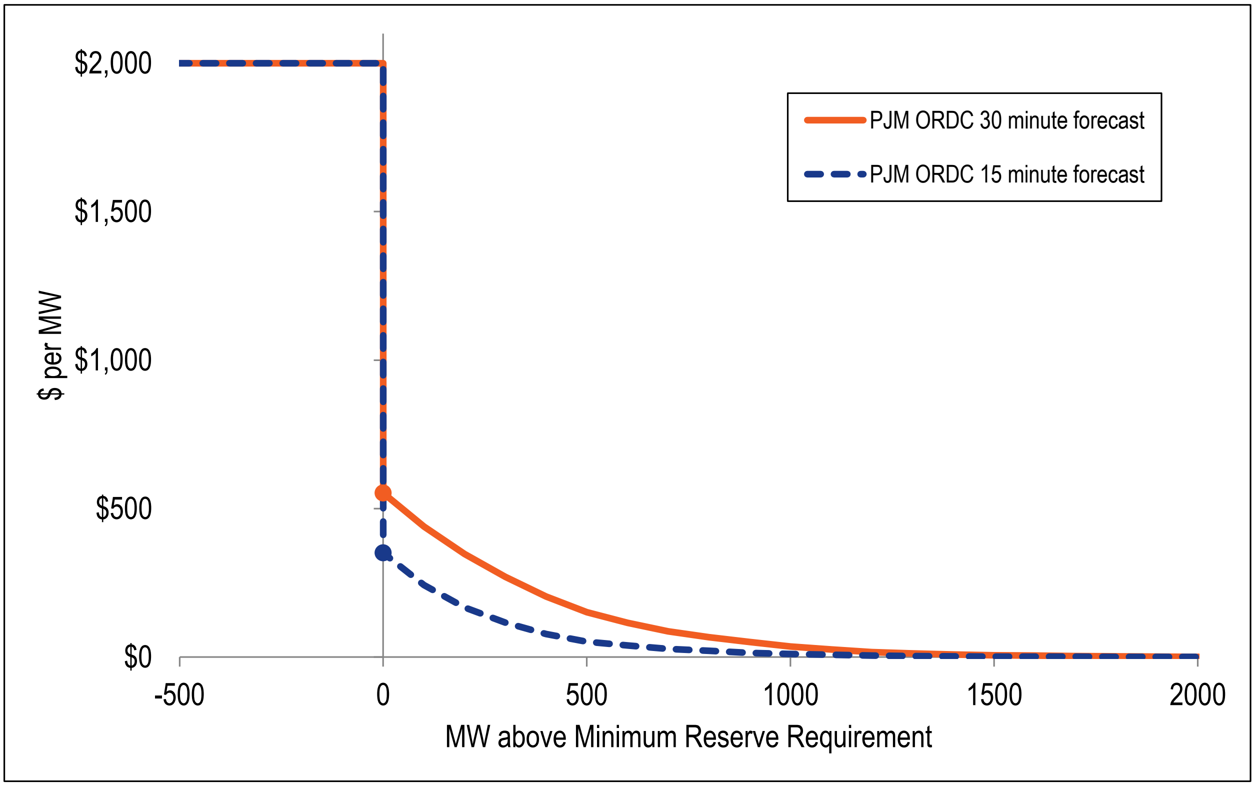
67 The NERC's Generating Availability Data System (GADS) was the source for the forced outage MW data.

68 Rocha Garrido Affidavit at P 15.

Figure 9 PJM ORDCs: 30 minute look ahead versus 15 minute (Summer, Time Block 5)



Cleared synchronized reserves are 9.5 percent lower and reserve revenues are 32.8 percent lower using 15 minute forecast error rather than 30 minute forecast error in the synchronized and primary reserve ORDCs.[69] The change in the magnitude of the ORDCs significantly changes the outcomes in the reserve market. However, the outcomes in the energy market do not change as much. The decrease in energy prices and revenues with 15 minute forecast error in the ORDC is only 0.4 percent. The primary impact of the extended sloped ORDC is in the energy market, and the size of the ORDC extension beyond the minimum reserve requirement has only a small impact on the large energy market outcomes. Using 30 minute uncertainty instead of 15 minute uncertainty is incorrect, unjust and unreasonable, but the broader problem with March 29th Filing's proposal is the

69 Attachment B: IMM Simulation Report at Table 1.

extended downward sloping ORDCs, regardless of the degree of uncertainty they quantify, and their pervasive effect on the energy market.

b. *PJM ignores the fact that forecast error may prevent rather than create shortages, overstating the probability of a shortage.*

By forcing the ORDC to be $2,000 per MW up to the minimum reserve requirement, PJM ignores the positive probability events where the RT SCED is short but the forecast errors are such that the market is really not short.[70] [71] In other words, the RT SCED is short reserves but due to an over forecast of load or an under forecast of wind or solar generation there is sufficient online generation and offline reserves to meet the energy and reserve requirements. If the ORDC is to price at the penalty price times the probability of a shortage given current conditions, then they should apply the same logic when RT SCED is short reserves as well as when RT SCED is long reserves.

PJM incorrectly states that the probability of reserves falling below the minimum reserve requirement is 100 percent "for reserve quantities between zero and the MRR." [72] [73] PJM administratively forces the value of the PBMRR to equal 1.0 for reserve values between zero and the MRR. The calculated probability is clearly not equal to 1.0 since the probability value corresponding to a target reserve level equal to the MRR is the basis for defining a critical point on the ORDC. PJM describes this critical point on the ORDC in its revised Operating Agreement language as follows:

> Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below

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70 March 29th Filing at 52.

71 Rocha Garrido Affidavit at paras. 17-19.

72 PJM uses the term PBMRR in reference to the probability of reserves falling below the minimum reserve requirement.

73 *See* March 29th Filing at 63.

> the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserve beyond the minimum reserve requirement.[74]

The probability value associated with Point (3) is clearly not equal to 1.0, and has not been asserted to be equal to 1.0 in documentation provided by PJM during the stakeholder process.

Figure 10 shows PJM's proposed ORDC for Summer, Time Block 5, and an alternative price curve that extends PJM's expected value calculation to events where the RT SCED is short. The curve in Figure 10 reflects the results of the probability analysis. When RT SCED is 100 MW short, the calculations find a 0.34 probability that the market will be short reserves, and the corresponding point on the price curve is $684.28 per MW. When RT SCED is 500 MW short, there is a 0.64 probability that the market will be short reserves and the corresponding price on the price curve is $1,286.72 per MW. Point (3) is also shown in Figure 10. The probability value associated with Point (3) is 0.28, indicating that the probability of incurring a shortage when the target reserve amount is equal to the minimum reserve requirement is 0.28. The corresponding price is $552.17. It is not just and reasonable for PJM to ignore forecast error when it indicates a lower probability that shortages may occur.

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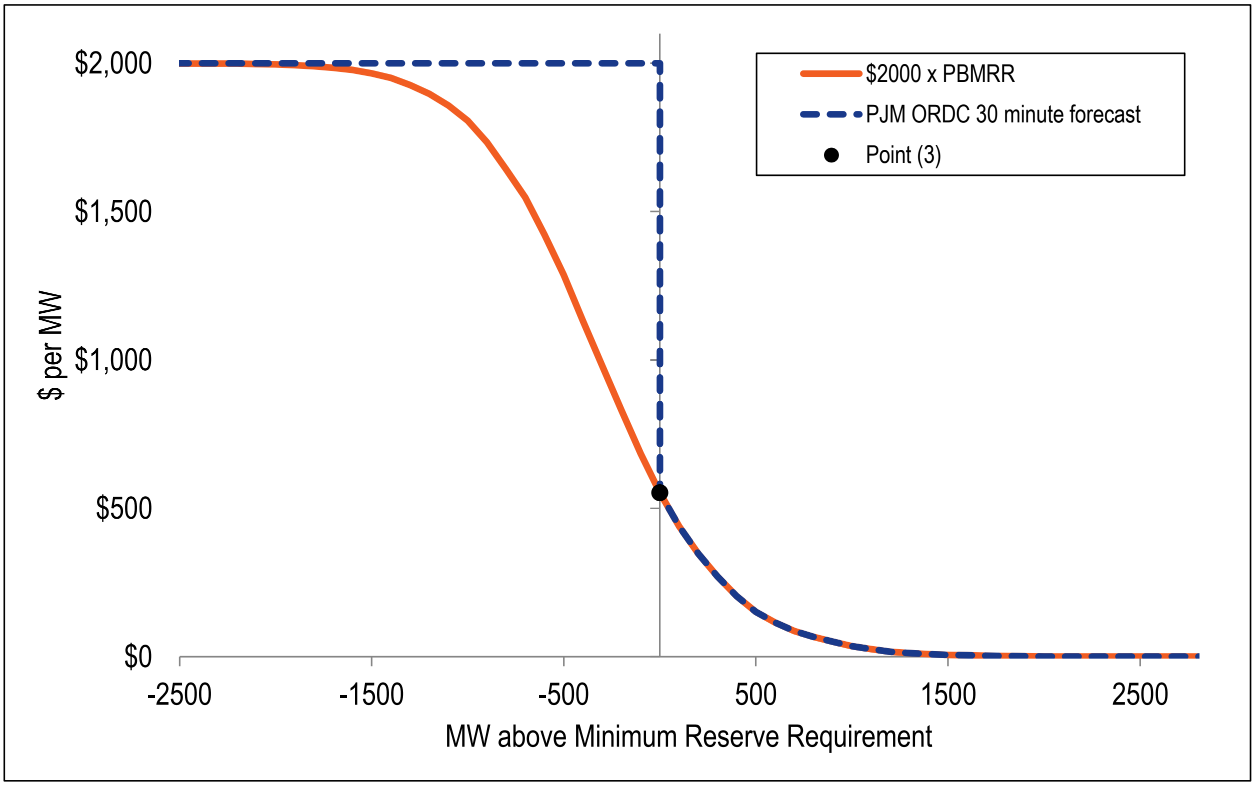
74 *See* March 29th Filing, Attachment B, "Revisions to the PJM Operating Agreement (Clean)", Section 3.2.3A.02(b)(ii)(C).

Figure 10 PJM proposed ORDC and the PJM calculated expected value of reserves



c. PJM fails to define a process for calculating a zonal ORDC.

PJM has not provided its process for calculating for the zonal ORDCs.[75] PJM claims that it will use load, wind output, solar output, forced outages, and interchange forecasts to calculate the zonal ORDC, but PJM does not explain the location of such load, generation, and interchange relative to the zone. Because resources outside the zone can be used to meet the zonal requirement, it does not make sense to calculate the PBMRR solely based on load and resources inside the zone. PJM also says it will use a zonal estimate of net interchange forecast. However, the PJM interchange applies to the entire RTO, not a subpart of PJM. Net interchange is by definition an RTO wide concept. PJM says that no tariff revisions are necessary to describe the calculation of zonal ORDCs, but the method for

[75] Rocha Garrido Affidavit at para. 25.

such calculation is not clear. It is not just and reasonable to calculate prices based on vague assertions without a clear, defined and transparent zonal ORDC calculation.

d. The proposed OA language does not provide adequate details and differs from PJM's calculations.

The language in proposed OA, Schedule 1, Section 3.2.3A.02 does not provide sufficient transparency into the process for calculating the ORDCs. Any details and assumptions about how the data is collected, how the empirical distribution is formed, how the curve is constructed, or how the regulation requirement is accounted for should reside in the OA, not the PJM Manuals. For example, in PJM's calculations using 2015 through 2017 data, it uses no solar forecast error for 2015 and 2016. PJM assumes that solar forecast error was similar to 2017 in the prior years and applies 2017 forecast errors to 2015 and 2016. In making its ORDC calculations, PJM also approximates the curve described in the proposed OA with a 100 MW stepped curve that understates the proposed ORDC.

PJM describes ORDC "Point 3" in the proposed OA.[76] Point 3 is the point (MRR, y) where y is the value "resulting from multiplying the Reserve Penalty Factor … by the probability of falling below the [MRR] when procuring an infinitesimal amount of additional MW of reserves beyond the [MRR]." In Figure 11, the price level corresponding to Point 3 is $552.17. The first block of the curve, as presented to the Energy Price Formation Senior Task Force (EPFSTF) and as used in the PJM simulations included in the March 29th Filing, is at the $438.9 price level. There is a discrepancy of $113.29 per MW between the method described in the proposed OA and the PJM calculation.

The discrepancy occurs because the y component of Point 3 is equal to $2000 x (Probability that the sum of forecast errors and forced outages exceeds zero MW). The height of the first block below $2000 per MW in the block curve is equal to $2000 x (Probability that the sum of forecast errors and forced outages exceeds 100 MW). The PJM

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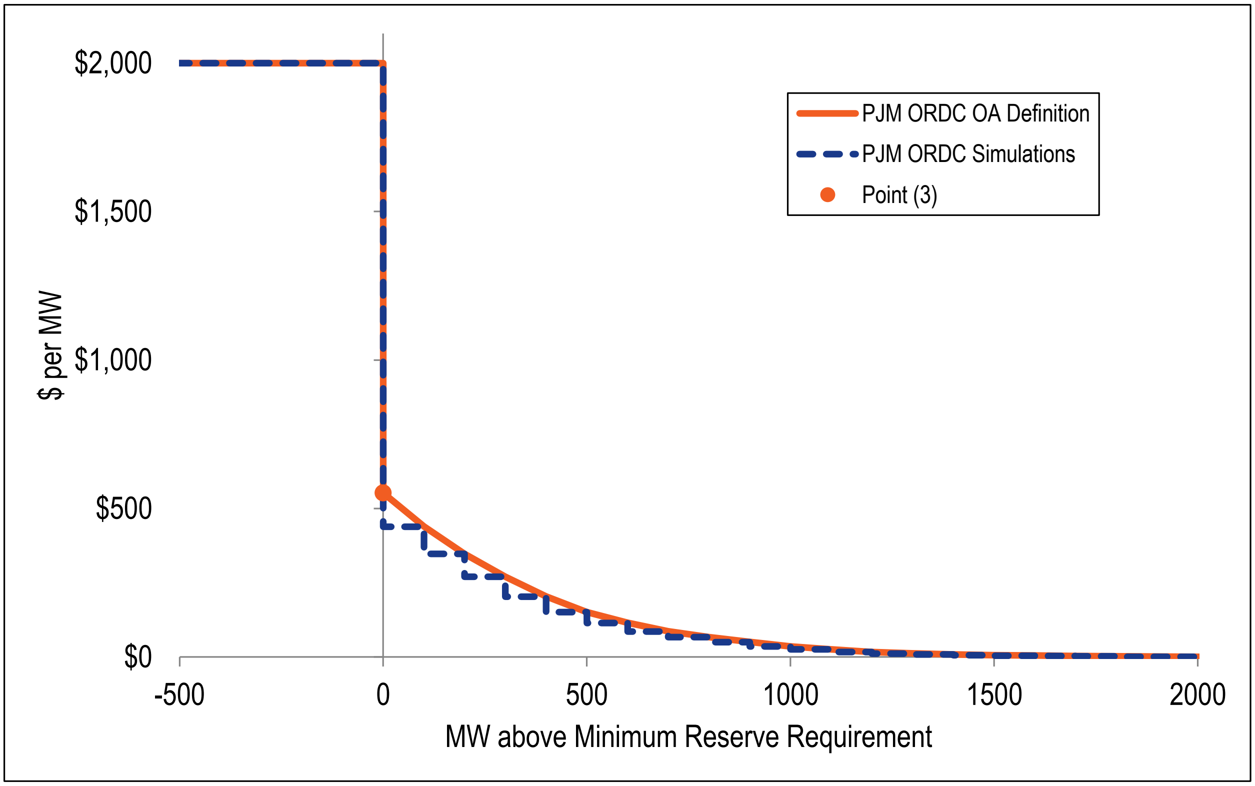
[76] March 29th Filing at Proposed Operating Agreement, Schedule 1, Section 3.2.3A.02(b)(ii)(C).

calculations and simulations use the 100 MW block curves which do not include Point 3. The chosen method for applying the calculation has a considerable impact on the ORDC prices.[77]

If PJM intends to use 1 MW or 10 MW block curves upon implementation, the height of the first block will be considerably higher (up to 25 percent higher in the example above) than the values shown to stakeholders in PJM EPFSTF materials and demonstrated to the Commission in the simulation results presented in the March 29th Filing.

Figure 11 PJM ORDC as calculated and as described in the proposed OA



[77] The Market Monitor reran the simulations with the PJM 30 minute ORDCs modeled with variable block sizes. One MW blocks were used for the portion of the ORDC with higher values and the block size was gradually increased as the ORDC approached $0 per MW. The simulation results show an increase of $10 million (5.3 percent) in reserve revenues over the simulation that modeled the entire ORDC in 100 MW blocks.

e. Data issues with PJM's calculations

The Market Monitor has identified several issues with the data used to calculate the PJM ORDCs. The most substantive error concerns the calculation of forced outage MW. PJM did not properly account for overlapping outage events in the GADS data. The forecast data for load, wind generation, and solar generation is incomplete, and includes incorrect data.[78] The forecast data and the forced outage data were not properly joined due to a mismatch in the respective timestamps.[79] It is not clear how significant an impact these data issues had on the PJM revenue estimates but clearly PJM needs to develop a well defined process for the calculation of the ORDCs. The process used throughout the stakeholder process and in the preparation of supporting materials for the March 29th Filing was clearly not adequate.

4. PJM's Proposed ORDC Procures More Reserves than Operators Have Historically Committed.

PJM claims that its ORDC is intended to replace historic operator actions to procure reserves with market procurement of reserves.[80] The Market Monitor estimates that the ORDC will increase the amount of primary reserves carried by PJM by an average of 1,354 to 1,376 MW per hour, 56.8 to 57.7 percent.[81] PJM says that the reserve requirements with the ORDC "would be more reflective of actual operator needs."[82] This implies that the PJM operators have historically operated the system with reserves far short of their actual needs.

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78 There are six hours over the three year period with no observations, five hours with missing wind forecast data, and five hours with missing solar forecast data. There were 24 observations where the solar forecast exceeded 1,600 MW which is approximately double the current solar ICAP. It is not clear if PJM excluded these observations.

79 The PJM forecast error (load, wind, and solar) data uses Eastern Prevailing Time. The forced outage data uses Eastern Standard Time.

80 March 29th Filing at 54–55.

81 Attachment B: ORDC Simulation Results at Table 1.

82 March 29th Filing at 54.

There is no support for this assertion. PJM rarely enters actual shortage conditions. PJM's own ORDC calculations find a 3.8 to 15.2 percent probability that a shortage will occur, depending on the time of day and year, at the historic average primary reserve level of 300 MW above the approximately 2,100 MW reserve requirement.[83] PJM does not experience reserve shortages at this rate. In fact, PJM had zero five minute market intervals of primary reserve shortage in 2018.[84]

Figure 12 shows an ORDC calculated by PJM compared to the historic median level of synchronized reserves carried by PJM. It shows that the ORDC assigns a high price to reserves at normal historic levels. Assigning the high price, means that the market software will assign a high value to procuring significantly more reserves than PJM has historically carried. Assigning the high value causes the market to commit more generation to come online, shifting the supply curve for reserves to the right and procuring more reserves based on where the ORDC intersects the supply curve for reserves.

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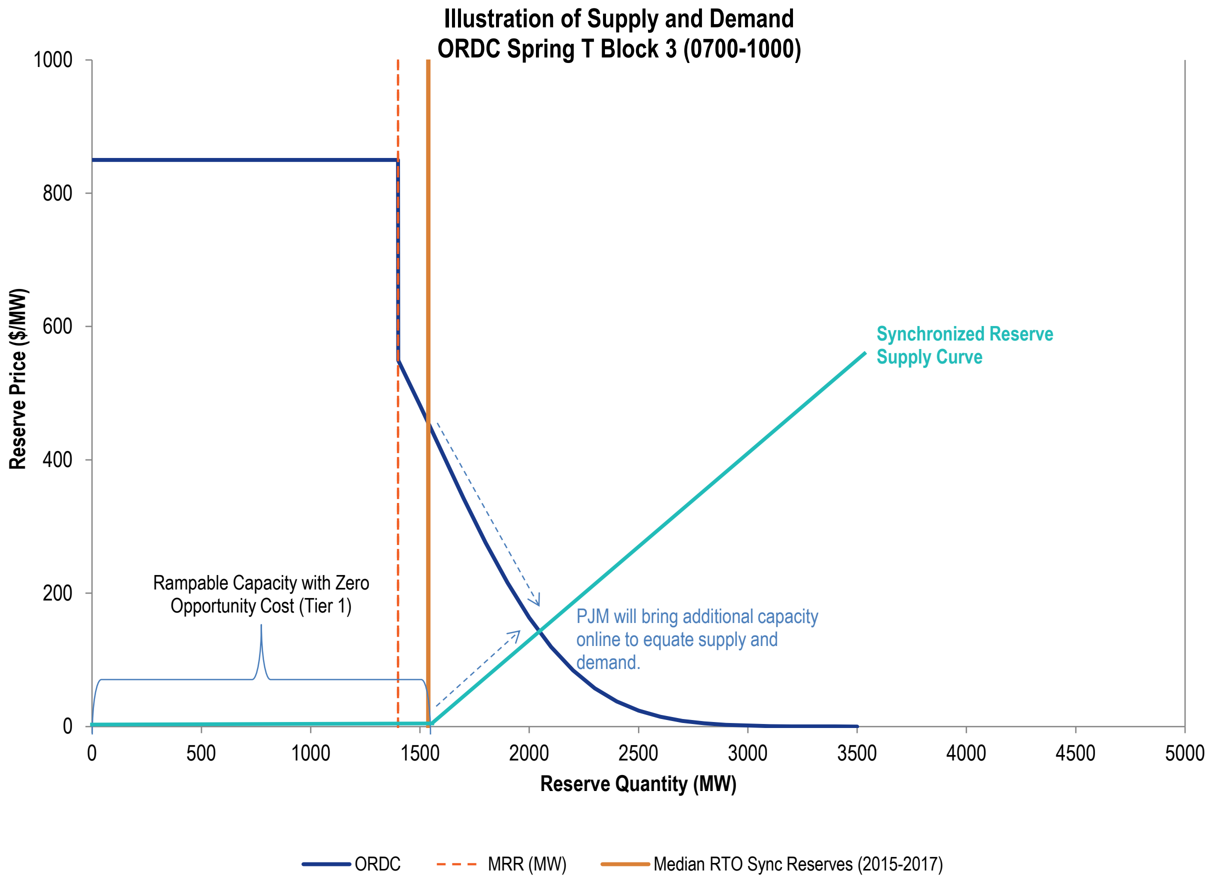
83 PJM, Primary Reserves – New Forced Outages Methodology, spreadsheet with ORDC calculations, prepared for the Energy Price Formation Senior Task Force (March 13, 2019), <https://pjm.com/-/media/committees-groups/task-forces/epfstf/20190314-pf/20190314-primary-reserves-new-forced-outages-methodology.ashx>, accessed May 9, 2019.

84 Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at 209.

Figure 12 PJM Proposed ORDC compared to historic reserves



To justify the ORDC's procurement of additional reserves, PJM presents an analysis of operator load bias in the Intermediate Term Security Constrained Economic Dispatch (IT SCED) process.[85] PJM claims that the operator bias prevented shortages in 29.1 percent of five minute intervals in 2018.[86] However, PJM does not present a full picture of the use of bias in IT SCED and misstates its impact based on a biased statistical analysis. In 2018, PJM operators only applied positive bias to 33.8 percent of IT SCED cases, with an average bias of 1,288 MW. Operators applied negative bias to 45.7 percent of IT SCED cases, with an average bias of -746 MW. PJM concludes that based on the amount of positive bias applied

85 March 29th Filing, Pilong Affidavit paras. 8–17.

86 March 29th Filing at 54.

in IT SCED cases, PJM operators prevented shortages of RTO wide synchronized reserves. PJM ignored the negative bias applied in IT SCED cases in 2018. Using PJM's faulty logic, if PJM operators saved the market from shortage 29.1 percent of the time by using positive bias, they would have created shortages a similar amount of the time by using negative bias. The selective use of IT SCED cases to suggest that operator bias is related to the actual observed synchronized reserve levels is speculative at best. There is nothing wrong with operators biasing IT SCED cases. Operators will not cease to bias IT SCED cases if the proposed ORDCs are implemented. The use of IT SCED bias is not evidence that PJM's proposed ORDCs are required or a just and reasonable approach.

Table 2 shows the number and percent of IT SCED cases that are positively biased, negatively biased, and unbiased in 2018. The data shows that operators bias IT SCED cases down more often than they bias cases up. Only 33.8 percent of the IT SCED cases are biased to increase the demand. An increase in demand through the bias would lead the IT SCED solution to recommend committing additional units. A decrease in demand through negative bias would lead the IT SCED solution to recommend committing fewer units than required to meet forecast load and reserves or ramping down existing generation to meet lower than forecast demand indicated by the negative bias.

Table 2 IT SCED operator load bias: 2018

IT SCED Bias	No. of approved IT SCED cases	Percent of approved IT SCED cases cases	Average Bias MW
Positive Bias	35,565	33.8%	1,288
Unbiased	21,631	20.5%	0
Negative Bias	48,148	45.7%	(746)
Total Cases	105,344	100.0%	

PJM also overstates the impact of IT SCED results on reserves. One MW of IT SCED load bias does not create one MW of reserves. IT SCED by itself does not commit or dispatch units. It plays an advisory role in presenting the options available to dispatchers given the forecast load, generation availability, transmission constraints, and bias. There is no evidence that operators strictly follow IT SCED results or follow it in any defined way.

The market requires that operators make decisions in response to real-time market conditions. PJM's proposal would not eliminate the need for operators to make decisions. PJM's proposed ORDCs would not substitute for real-time operator actions as PJM claims.[87] PJM proposes to form the proposed ORDCs based on historic average forecast error, which will not match the real-time forecast error that the operators respond to in committing units in the IT SCED process. The proposed ORDCs may be formulaic, but they do not formulaically match actual minute by minute market conditions. PJM's arguments do not provide evidence that the proposed ORDCs will match the actual needs of the operators. These arguments do not support the claim that PJM's proposed ORDCs are just and reasonable.

5. PJM's Proposed ORDCs Provide More Benefits to Inflexible Resources than Flexible Resources.

PJM provides no evidence to support its claim that "the comprehensive reforms set forth in this proposal will incentivize the development of flexible resources."[88] The current PJM market design has provided strong incentives for flexible units. Almost without exception, new capacity built under the PJM market design has been combined cycle units, which are highly flexible. Any incentive to develop flexible resources created by increased reserve revenues is more than offset by increases in energy revenues to inflexible resources. Because the primary effect of the ORDC is the increase in energy prices, PJM's proposal increases generator revenues more for inflexible units than for flexible units. With incentives for both inflexible and flexible resources, PJM cannot accurately claim that its proposal will increase the flexible proportion of PJM capacity. The current trend in PJM is

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87 March 29th Filing, Pilong Affidavit at para. 20.

88 March 29th Filing at 70.

toward the retirement of inflexible capacity, but PJM's proposal could reverse that trend by creating a new source of revenue that delays the competitive retirement of inflexible capacity.

The Market Monitor's analysis of simulation results shows that nuclear resources would receive the largest increase in energy revenues from PJM's proposal at $15,345 per installed MW of capacity for the simulated year 2018. Nuclear units are the least flexible resources in the PJM market. The simulation results show that some flexible technologies, currently with very small market shares in PJM, would benefit as well. Natural gas reciprocating engines would receive an increase of $14,467 per MW-year, which includes the largest increase of any technology in reserve revenues. Natural gas combined cycle units would receive an increase of $8,922 per MW-year with 18.3 percent of the increase coming from the reserve markets. Natural gas combined cycle units provide the vast majority of the increased MW of reserves that clear in the simulation with PJM proposed ORDCs, but the increase in revenues to combined cycles is only 58.1 percent of the increase in nuclear unit revenues per MW of capacity. Combustion turbines and steam coal units would receive an increase of $5,910 and $6,952 per MW-year in energy and reserve revenues. Table 3 shows the simulated revenue increases for Case A compared to Case C.[89]

[89] The relative increases across technology are similar for PJM's preferred Case B to C comparison, though the magnitudes are smaller. The revenues by technology are shown for all cases in Attachment B.

Table 3 Simulated revenue increases for PJM's proposal by resource technology

	Revenue ($/MW)								
	Case A			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$3,604.36	$0.00	$0.00	$3,798.43	$13.33	$1.38	$194.07	$13.33	$1.38
CC	$155,967.75	$359.99	$0.01	$163,258.56	$1,991.24	$0.09	$7,290.80	$1,631.25	$0.08
CT Natural Gas	$32,156.09	$191.51	$64.56	$36,990.46	$1,075.46	$255.89	$4,834.37	$883.95	$191.33
CT Oil	$9,983.78	$371.02	$935.72	$11,849.83	$1,263.09	$2,857.71	$1,866.05	$892.07	$1,921.99
CT Other	$127,698.41	$193.26	$437.72	$134,586.24	$927.62	$1,367.07	$6,887.83	$734.36	$929.35
Fuel Cell	$238,226.92	$0.00	$0.00	$251,877.32	$0.00	$0.00	$13,650.40	$0.00	$0.00
Hydro	$57,912.74	$285.61	$10.88	$60,669.54	$1,183.75	$32.89	$2,756.80	$898.15	$22.01
Nuclear	$247,331.25	$0.00	$0.00	$262,676.13	$0.00	$0.00	$15,344.88	$0.00	$0.00
RICE Natural Gas	$109,071.16	$544.33	$0.00	$120,250.00	$3,832.01	$0.00	$11,178.85	$3,287.68	$0.00
RICE Oil	$5,665.43	$8.52	$380.87	$6,099.79	$32.41	$1,153.61	$434.36	$23.89	$772.74
RICE Other	$141,785.61	$1,047.20	$130.08	$149,025.68	$3,871.55	$391.63	$7,240.07	$2,824.35	$261.55
Solar	$45,967.24	$0.00	$0.00	$48,389.13	$0.00	$0.00	$2,421.88	$0.00	$0.00
Steam Coal	$125,943.83	$59.30	$0.04	$132,513.86	$440.62	$0.67	$6,570.03	$381.32	$0.62
Steam Natural Gas	$28,178.89	$53.63	$0.02	$27,725.22	$263.42	$0.00	($453.67)	$209.79	($0.02)
Steam Oil	$16,867.86	$19.25	$0.00	$17,831.52	$81.66	$0.00	$963.66	$62.41	$0.00
Steam Other	$186,497.86	$138.91	$0.00	$196,423.60	$519.02	$0.00	$9,925.74	$380.11	$0.00
Wind	$64,478.96	$0.00	$0.00	$68,888.98	$0.00	$0.00	$4,410.02	$0.00	$0.00
Total	$128,180.23	$147.65	$26.65	$135,432.01	$816.86	$88.55	$7,251.78	$669.22	$61.91

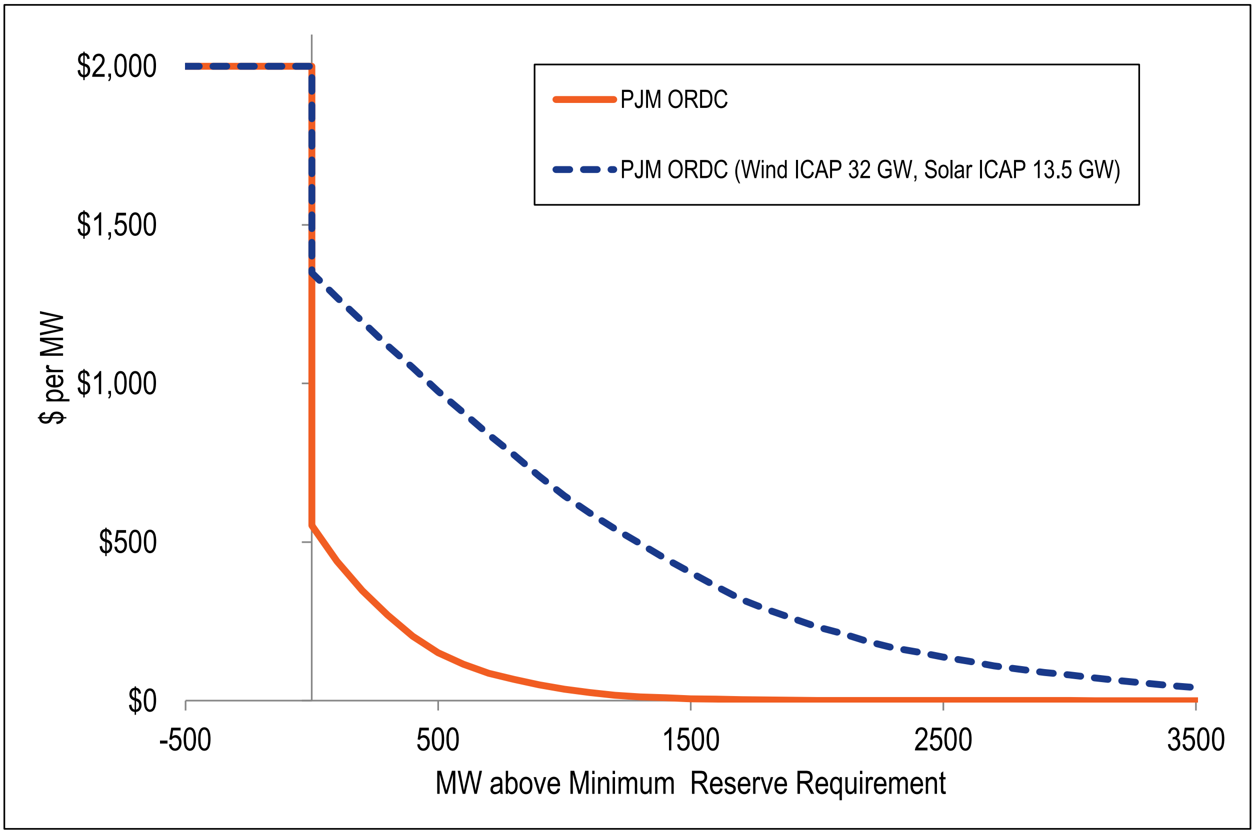
The simulation results are not consistent with PJM's assertion that the PJM ORDC provides incentives for flexibility in PJM's market. PJM's proposed ORDC would create a windfall for inflexible capacity that does not provide reserves. A just and reasonable market design to promote flexibility does not benefit inflexible units more than flexible units. PJM's proposal to pay higher energy revenues to all units through the extended sloped ORDC is not just and reasonable.

6. The Proposed ORDCs Reach Unreasonable Levels Under PJM's Forecasted Renewables Penetration.

PJM's rationale for its proposed ORDC is based in significant part on the assertion that there will be very substantial increases in wind and solar generation in the near future. If the wind and solar resources predicted by PJM enter the market, PJM's method for calculating the proposed ORDCs based on wind and solar forecast error would result in a substantial shift in the ORDC and a substantial increase in energy and reserve prices. The Market Monitor used PJM's historic wind and solar forecast error method and scaled the wind and solar MW up to 32.0 GW of wind and 13.5 GW of solar capacity to match PJM's predictions of an additional 25 GW of wind and 12 GW of solar on top of PJM's current 7 GW of wind and 1.5 GW of solar capacity.[90] Figure 13 shows the summer afternoon peak, time block five, ORDC with the scaling of the wind and solar forecast error. The price increase is approximately $500 per MW for the first 1,000 MW of reserves beyond the reserve requirement. Such high reserve prices would overwhelm the marginal cost component of LMP with the scarcity adder. These results demonstrate that PJM's method would produce unreasonable outcomes under the conditions that PJM predicts. These results demonstrate that PJM's method for calculating the ORDC using estimated forecast errors is fundamentally flawed. PJM failed to address these outcomes in its filing. The proposed ORDC is not just and reasonable because it produces unreasonable outcomes under PJM's expected market conditions.

[90] See March 29th Filing at 7.

Figure 13 Proposed ORDC Scaled to Reflect Higher Future Wind and Solar Capacity



7. PJM Fails to Address the Necessary Revenue Offset in the Capacity Market.

In the PJM market design, the energy and the capacity market together provide the opportunity for generation resources to recover all their costs including a return on and of capital. The capacity market serves the same function as scarcity pricing, to provide revenues missing when the energy market clears at the short run marginal cost of a peaker. The two market-based ways to ensure that the missing money is provided are scarcity pricing and capacity market revenue. Cost of service ratemaking, as practiced in MISO and SPP, are a nonmarket-based way to address the missing money. Capacity market revenue is scarcity revenue. In the PJM market design, the capacity market and scarcity pricing are complementary. The large proposed increase in energy and reserve market revenue to generators that would result from PJM's proposed ORDC is scarcity pricing revenue and is a substitute for capacity market revenue. PJM explicitly fails to address this fundamental market design fact. PJM's proposal is unjust and unreasonable as a result of this issue alone.

The design of the PJM Capacity Market recognizes the substitutability of scarcity revenue and capacity market revenue. The capacity market is designed to provide the opportunity to cover any shortfalls in energy and ancillary services markets revenue. The capacity market includes an energy and ancillary services (EAS) offset which explicitly accounts for changes in energy and ancillary services net revenue. Given the target level of revenue in the capacity market, as revenue from the energy and ancillary services markets increases, revenue from the capacity market decreases.

Although PJM was directed by the PJM Board of Managers to address the relationship between EAS revenues and capacity market revenues in its ORDC design, PJM failed to address the offset in its filing. PJM has not stated why it fails to address the offset issue. PJM's lack of clarity about its goals and about the interactions among the reserve market, the energy market, and the capacity market is further revealed in its unwillingness to address the offset issue. Despite PJM's attempt to misdirect the Commission by focusing on the reserve markets alone, the March 29th filing is about the entire PJM market design, including the reserve markets, the energy market and the capacity market and the interactions among them. The result of the March 29th filing will be to increase total compensation for generation, by increasing energy and reserve market revenue without an offset in the capacity market. PJM has not made clear that this will be the result, nor has PJM justified such an increase. If PJM's filing had made explicit that PJM's goal is to increase the revenue in the energy and reserve markets and correspondingly reduce the revenue in the capacity market, the shift of revenue resulting from the March 29th filing requires additional market design changes to ensure that the shift occurs and that it occurs effectively, equitably and efficiently and to ensure that the outcome is just and reasonable.

The additional market design changes required are the calculation and treatment of the EAS offset and the definition of the parameters of the capacity market demand curve. Unless specifically addressed, the higher energy and reserve prices will not result in an offsetting capacity market price and revenue reduction for the capacity market auctions that have already cleared. Unless specifically addressed, the higher energy and reserve prices will not result in an offsetting capacity market price and revenue reduction even for new capacity market auctions. PJM has not included any such specific changes to address these issues. Unless specifically addressed, the higher energy and reserve prices will not result in appropriately lower capacity market prices as a result of the definition of the maximum price on the capacity market demand curve. The EAS offset includes both energy market net revenues and ancillary services markets revenues including reserve market revenues.

PJM has requested an implementation date of June 1, 2020, for its ORDC proposal. That would mean that, if PJM's proposal is accepted, the Base Residual Auction for the 2023/2024 Delivery Year, scheduled for May 2020, would have been run and capacity market prices set prior to the implementation of the PJM ORDC proposal. If PJM's proposal is accepted, effective June 1, 2020, there would have been four Base Residual Auctions run that establish prices that will be effective after PJM's implementation of its ORDC proposal and effective during the period that the higher energy and ancillary services revenues resulting from PJM's proposal will be in effect. PJM's March 29th filing guarantees and locks in a mismatch between the energy and capacity markets in complete and explicit disregard for the complementary nature of the market design.

PJM's proposal will result in an increase in payments by load to generators of at least $1.7 billion per year for four years or $6.8 billion total during the transition period. If PJM's proposal is adopted, there needs to be a true up for the first four delivery years. PJM's proposal will also result in a significant overpayment by load to generators even after the first four delivery years. PJM's proposal would continue to base the EAS offset on historical net revenues. In the Base Residual Auction run in May 2021, the EAS offset would be based on the average net revenue in calendar years 2018, 2019 and 2020. In this Base Residual Auction, the EAS offset would include only seven months of increased revenues. Based on a June 1, 2020, effective date for the increase in energy and reserve revenues, PJM's proposal will result in an increase in payments by load to generators of an additional

$2.4 billion over the three Base Residual Auctions until the three years of history include three calendar years in which the ORDC was effective. The total increase in payments by load to generators over this period would be $9.2 billion.

If PJM' proposal is accepted and scarcity revenues are shifted from the capacity market to the energy market, there must be a clear and verifiable mechanism to ensure that the shift occurs and that the shift occurs effectively, equitably and efficiently. The current capacity market demand curve (VRR) will result in substantial overpayments unless modified in specific ways. The increased energy revenues will not result in lower capacity market prices and revenues without these modifications. In the absence of a clear, verifiable and correctly defined mechanism, substantial overpayments will occur long term and a core feature of the PJM market design will be compromised and distorted.

The energy and ancillary service (EAS) offset affects the capacity market in several ways. The EAS offset affects the calculation of net CONE and therefore the shape and location of the VRR curve. The EAS offset affects the offer levels of capacity market sellers using offers based on net avoidable costs and on the currently defined market seller offer cap of Net CONE * B.

A clear, verifiable and correctly defined mechanism for the four Base Residual Auctions that will have cleared on the implementation date should return the scarcity revenues, unanticipated when the capacity market auctions were cleared, from PJM's proposed ORDC to customers. Customers paid and generators received capacity market prices and revenues based on an expectation that PJM's existing energy and reserve market design and scarcity pricing design would continue. Scarcity revenues in excess of that level of energy and ancillary services revenues would be double payment by customers and should be returned to load. If the PJM ORDC had been in place and those higher revenues had existed at the time the four Base Residual Auctions cleared, capacity market prices and revenues would have been lower. In that case, customers would have paid the additional ORDC based scarcity rents through the energy and ancillary services markets only and not both through the energy and ancillary services markets and the capacity market.

PJM's proposal creates double payment of scarcity rents by customers and double compensation of scarcity rents to generators, which is not a just and reasonable outcome.

8. PJM Does Not Correctly Account for 30 Minute Reserves.

PJM proposes to introduce a new secondary reserve product.[91] PJM argues that the 30 minute secondary reserve product is needed to align the day-ahead and real-time markets.[92] PJM provides no operational justification for a secondary reserve product, and there is no NERC requirement that PJM maintain 30 minute reserves. PJM's proposed secondary reserve product fails to include any of the 5,044 MW of pre-emergency and emergency demand response available to the market in 30 minutes in its secondary reserve market.[93] On the other hand, PJM allows any generator submitting start and notification times less than 30 minutes to participate, even though some of these generating units have do not maintain staff at the unit that would allow them to start within 30 minutes.

PJM's proposed penalty when a resource fails to provide secondary reserves is not sufficient. The proposed penalty only applies when PJM dispatches an offline unit during a period for which it has cleared secondary reserves.[94] The proposed penalty would remove the secondary reserve commitment and associated revenues for the operating day when the resource failed to respond to a dispatch instruction. The situation that would invoke the penalty is not likely to occur, because PJM dispatchers call the resource before issuing a dispatch instruction. If the resource is not able to start, the dispatchers' usual practice is to dispatch a different resource. Therefore, the resource that cannot start receives no dispatch

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91 March 29th Filing at 76.

92 March 29th Filing at 14.

93 Monitoring Analytics, *2019 State of the Market Report for PJM: January through March*, Vol. II, Section 6: Demand Response at Table 6-20.

94 March 29th Filing at 78.

instruction and may continue to clear reserves. The penalty is inadequate and not just and reasonable.

PJM's proposal for secondary reserves does treat all resources equally and does not include adequate performance incentives. It is not just and reasonable.

9. PJM Proposes Unnecessary and Complicated Settlement Rules that Do not Support Incentives to Follow Dispatch and Create Opportunities for Manipulation.

In the current market design, PJM uses lost opportunity cost uplift payments to ensure that inflexible resources, synchronous condensers and load response resources cleared for Tier 2 synchronized reserves, remain indifferent between providing reserves and energy throughout the operating hour in the real-time market. Due to their inability to respond to five minute changes in reserve dispatch, these inflexible resources are cleared in advance for an hour at a time. The five minute market clearing price may not cover the lost opportunity cost energy revenues for inflexible resources providing reserves. Flexible resources do not need lost opportunity cost payments, because the lost opportunity cost component of the synchronized reserve market clearing price already includes the lost opportunity cost of the marginal resource clearing reserves in each five minute market solution. PJM currently pays synchronized reserve market lost opportunity costs on a five minute basis, but it is not necessary to pay on a five minute basis. The costs and similar revenues offset each other throughout a resource commitment and should be part of the larger Balancing Operating Reserve make whole payment.

PJM proposes fundamental changes to the reserve lost opportunity cost credits that are not, as March 29th Filing claims, "just as in the energy market."[95] PJM does not pay energy uplift credits to all resources for all five minute market intervals when the resources

[95] March 29th Filing at 108.

make a loss on differences between day-ahead and real-time market outcomes.[96] PJM proposes that a resource should profit from any real-time or day-ahead lost opportunity costs when they are a credit to the resource, but PJM does not justify why it should pay this amount when it is a loss to the resource. PJM claims that the "credit is designed to ensure the resource follows PJM dispatch and is indifferent to providing reserve's and energy."[97] PJM does not explain why it thinks a resource will not follow its energy dispatch signal when PJM changes its cleared reserve MW.

The rules and proposed OA language for lost opportunity cost payments are unduly complex and unclear, which makes it unclear how PJM can consistently implement them. It also lends the uplift payments to potential manipulation. PJM's proposed lost opportunity cost credits for resources clearing reserves are unnecessary for market efficiency, do not provide any additional incentive to follow PJM's five minute reserve instructions, and are not just and reasonable.

10. PJM Proposes a Synchronized Reserve Offer Margin that Undermines the Incentive for Resources to Respond to Spinning Events.

While the Market Monitor supports PJM's proposal to remove the existing $7.50 per MW synchronized reserve offer margin, PJM's proposal to replace it with the expected value of the synchronized reserve performance penalty undermines the incentive for resources to respond to spinning events.[98] Allowing resources to include expected penalties in offers would require customers to pay for suppliers' noncompliance. While the historic expected value of the penalty is low, the increases in reserve prices and revenues under PJM's proposal would significantly raise the expected penalty. An offer margin based on expected performance noncompliance penalties is not just and reasonable.

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96 March 29th Filing at 111–112.

97 March 29th Filing at 112.

98 March 29th Filing at 46.

11. PJM Proposes an Insufficient Penalty for Synchronized Reserve Nonperformance.

The current synchronized reserve performance penalty, which PJM proposes to maintain, is insufficient to support an enhanced reserve market design. Under the penalty structure it is possible for a resource to not respond to any spin events and yet be paid for providing synchronized reserve. The penalty structure for synchronized reserve nonperformance is not adequate to provide appropriate performance incentives.

A synchronized reserve resource is penalized for all hours in the Immediate Past Interval (IPI) based on the amount of MW it falls short of its scheduled MW during an event and for any hour in that day for which it cleared. The penalty period is calculated as the lesser of the average number of days between spinning events over the past two years (ISI) or the number of days since the resource last failed to respond fully. For 2018, PJM used the average number of days between spinning events from November 2016 through October 2018, which is 19 days. Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from a different unit to reduce an under response penalty.

The penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event involves two components. The resource foregoes payment for the MW of under response for all cleared hours of the day of the event. The resource is charged a penalty in the amount of its MW of under response during the spinning event against all of its synchronized reserve revenues during the Immediate Past Interval (IPI) or since the resource last failed to respond to a spinning event, whichever is less. IPI is calculated yearly on December 1 as the average number of days between spinning events over the past two years. Participants with more than one resource can aggregate their response from over responders to offset under responders during an event.

Under the penalty structure, nonperformance is only defined for spinning events of 10 minutes or longer. For events of less than 10 minutes, all resources, regardless of actual performance, are considered to have performed perfectly. But the IPI is defined as the number of days between spinning events, regardless of duration. This definition artificially shortens the period since the last requirement to perform.

In addition, allowing an organization to aggregate responses from all online resources is a mistake because it weakens the incentive to perform and creates an incentive to withhold reserves from other resources. The obligation to respond is unit specific.

Based on an analysis of six of the most heavily scheduled resources in the synchronized reserve market, shown in Table 4, the Market Monitor concludes that under the current penalty structure, completely unresponsive resources would be paid for providing reserves. The analysis covered the period from the April 1, 2018, introduction of five minute pricing, through December 31, 2018. For resources that completely fail to respond for all spinning events, resource owners would earn 58.2 percent of what they would earn from a perfect response. A penalty structure that allows for this result is not just and reasonable.

Table 4 Tier 2 synchronized reserve market penalties: April 1, 2018 through December 31, 2018

Total Scheduled MWh	Actual Spinning Event Shortfall MWh	Credits for Hypothetical T2 Response of 100%	Credits for Hypothetical T2 Response of 0%	Actual T2 Credits	Actual Credits Under IMM Proposed IPI Change
24,926	609	$1,350,022	$786,492	$1,345,571	$1,343,272

12. PJM's Generator Modelling Does Not Accurately Measure Reserves.

PJM proposes very precise pricing at various levels of reserves using the extended sloped ORDCs. The precision of this pricing is misleading because the precision of PJM's measurement of reserves does not match the precision of the ORDCs.

PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. These simplifications and assumptions manifest themselves when generators do not follow or cannot follow PJM's instructions (following dispatch). From the dispatchers' point of view, units that do not accurately follow dispatch cannot be relied upon. PJM addresses this issue by adjusting the parameters submitted by generators using historical performance or by simply assuming that the generator will not follow PJM's instruction.

Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM Manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM Manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the Energy and Reserve Markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM ignores the complexities that may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generators parameters, called Degree of Generator Performance (DGP).[99] PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time. Not accounting for soak time output in the market software will cause PJM to procure more reserves than indicated by the ORDC under its proposal.

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[99] *See* PJM Manual 12 (Revision 39, Effective February 21, 2019) Attachment A, P78. PJM Manual 11 (Energy and Ancillary Services Market Operations) does not mention the use of DGP in the market clearing engine.

Over the years, PJM has acquired enough data and experienced enough events to not trust generators operating parameter data. This mistrust is reflected in PJM's adjustment of generation parameters and eligibility to provide reserves. PJM explains that it "has taken many steps to better align its Tier 1 estimate to be more reflective of expected performance of the generator."[100] PJM adjusts ramp rates using the DGP metric, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set it equal to actual resource output. PJM's proposal does not address any of these issues. Under PJM's proposal, generators will continue to not follow dispatch due to parameters, not because they cannot but because the PJM models do not account for their operational characteristics. Under PJM's proposal, PJM dispatchers will continue to adjust the amount of energy and reserves that they can rely on from generators regardless of the generator submitted parameters. PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. In addition to the other issues with the ORDCs, the proposed ORDCs cannot deliver the promised improvements in market flexibility claimed by PJM as a result of the underlying inaccuracies in reserve measurement.

13. PJM Resources Do Not Follow Dispatch Signals.

The March 29th Filing proposes to substantially increase reserve revenues and to increase LMP based on five minute energy and reserve dispatch calculations. The five minute dispatch calculation assumes that resources perform consistent with that calculation. However, PJM does not price energy and reserves consistently, undermining the price incentive for resources to follow dispatch.[101] PJM also pays uplift to resources based on their actual metered output rather than the desired output communicated from the dispatch solution. Paying uplift based on the actual, rather than the desired, output

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[100] March 29th Filing at Pilong Affidavit at para. 24.

[101] Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market at 203–204.

undermines the incentive to follow dispatch. The proposed ORDC pricing assumes that resources follow dispatch.

PJM does not have processes in place to accurately determine whether or not resources follow dispatch instructions. PJM's current method for calculating the MW off dispatch and percent off dispatch is fundamentally flawed. As a result PJM does not accurately calculate generator MW deviations and thus cannot determine whether or not resources follow dispatch instructions.[102]

To implement the proposed new pricing, lost opportunity costs, and new uplift payments based on PJM's current processes related to following dispatch signals is not just and reasonable.

C. The Market Monitor Provides a Superior Solution That Procures Reserves at Just and Reasonable Rates.

The Market Monitor does not agree with PJM that the current market design produces unjust and unreasonable rates. The Market Monitor recommends that PJM's proposal be rejected in its entirety for that reason and because PJM's proposal would itself result in unjust and unreasonable rates. PJM can and should pursue improvements to its market rules through the stakeholder process. The Market Monitor believes that the basic elements of its proposal have a high probability of receiving super majority support from PJM stakeholders. The Market Monitor's proposal received the most support in the final Energy Price Formation vote of the Markets and Reliability Committee.[103] The Market Monitor's proposal is a conservative approach to addressing identified areas of

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102 *See* Monitoring Analytics, Following Dispatch, presentation to the Energy Price Formation Senior Task Force (January 17, 2019), <*http://www.monitoringanalytics.com/reports/Presentations/2019/IMM_EPFSTF_Following_Dispatch_20190117.pdf*>.

103 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.

improvement without radically modifying the PJM market design and without requiring a finding that PJM energy and reserve markets are not just and reasonable.

In the event that the Commission determines that the current reserve and energy market rules are unjust and unreasonable, the Market Monitor recommends adoption of the Market Monitor's proposals. In this Section 206 proceeding, the Commission can "determine the just and reasonable … rule."[104] The Act requires no deference to PJM's proposal.

The Market Monitor proposes rule changes that would directly address the issues of operator actions suppressing prices, appropriate ORDC penalty factors, coordination of day-ahead and real-time market reserve products, adequate penalties for lack of reserve performance, consolidation of the Synchronized Reserve Market, and incorporation of demand resources in reserve markets.

The Market Monitor's proposals were developed and presented as part of the stakeholder process and there is no reason that these proposals could not be based on a vote in the ordinary course of a stakeholder process and a Section 205 filing.

1. Operating Reserve Demand Curves.

a. Operator Actions

In its April 11, 2018, letter to stakeholders the PJM Board of Managers identified the areas to be addressed by the Energy Price Formation Senior Task Force:

> In order to maximize the effectiveness of the markets in achieving this objective, the actions system operators take to maintain grid reliability must be reflected as transparently as possible in these market clearing prices. While this is certainly the case the majority of the time and there is ample evidence that the PJM markets are working efficiently to reinforce grid reliability, there are also instances where operator actions are not reflected in market prices. Therefore, there is room for improvement in how these energy and reserve prices are formed. Specifically, there are times

[104] 18 U.S.C. § 824e.

> when operators commit resources to ensure reliability but these commitments are not reflected through market clearing prices such that those prices can be suppressed and result in undesirable outcomes.[105]

The identified issue was the limited set of instances when conservative operator actions suppress energy and reserve prices despite stressed market conditions. PJM points to operator actions during winter peak load periods as evidence of the issue.[106] A straightforward and targeted method to account for operator actions in the market is to create rules which increase the reserve requirements to accurately reflect system needs when operators take actions. Expansion of the reserve requirement shifts the ORDC at a marginal value of reserves equal to the defined penalty factor as shown in Figure 3.

The Market Monitor proposes default reserve requirements for each reserve product and each zone using the Minimum Reserve Requirements for synchronized reserve and primary reserve as defined by PJM to support the NERC BAL-002 requirement.[107] The Market Monitor agrees that PJM should use the economic maximum output limit of the largest online generator as the basis for the default synchronized and primary reserve requirements. As there is no defined NERC requirement for secondary reserve, the Market Monitor proposes a default secondary reserve requirement of zero for each zone.

The Market Monitor proposes that the Commission require PJM to define in its OATT clear rules which increase the reserve requirements to accurately reflect system needs when operators take actions and which require the public posting of the applicable reserve requirements (synchronized, primary, or secondary), applicable zones, and explicit

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105 PJM Board of Managers, Letter to PJM Stakeholders, April 11, 2018. The objective described in the first sentence is "to incentivize physical asset owners to act in a manner that reinforces grid reliability."

106 *See* March 29th Filing at 20.

107 *See* March 29th Filing at Pilong Affidavit para. 21.

start and end times for the requirement changes. Shifting the reserve requirements allows operators to commit the resources they need without suppressing price, which is a just and reasonable proposal to address the potentially price suppressive effects of operator actions.

b. Penalty Factors

The shortage pricing penalty factor sets a cap on the amount the reserve market will pay to maintain reserves. If the goal is to ensure that all available reserves will clear before the market enters a shortage, the penalty factor should exceed the largest possible lost opportunity cost for a resource providing reserves instead of energy, which cannot exceed the highest short run marginal cost of any resource available for energy. That amount cannot be offered higher than $1,000 per MWh, but rarely reaches even the $1,000 per MWh level.

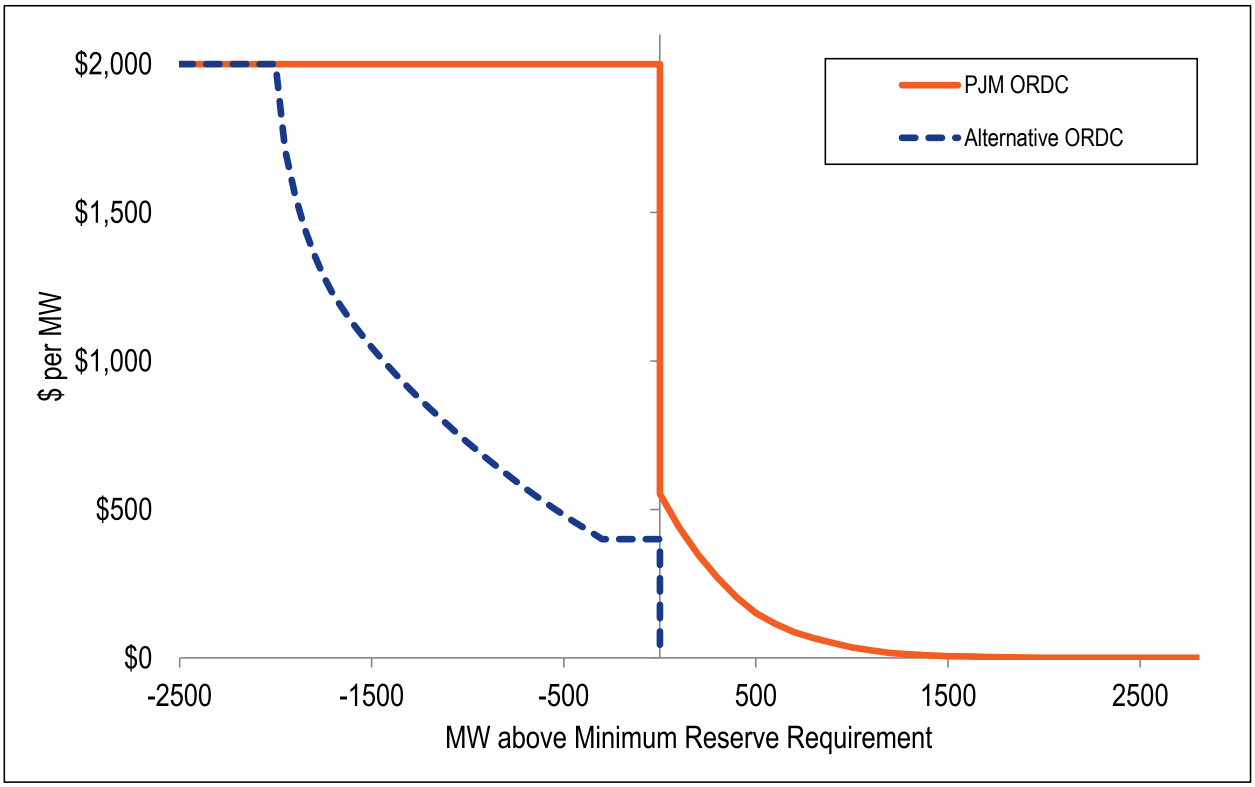
In the case when PJM has validated that the short run marginal costs of some resources exceed $1,000 per MWh, the penalty factor should adjust accordingly. The Market Monitor proposes raising the penalty factor in $250 per MWh increments for market hours when PJM approves short run marginal costs over $1,000 per MWh, such that the penalty factor exceeds the highest short run marginal cost in the market.

These proposed adjustments to the ORDC penalty factor would address PJM's claims that the penalty factor is not high enough to allow the market to efficiently dispatch reserves without imposing unduly high prices on customers based on nonexistent opportunity costs. The Market Monitor's suggested penalty factors are just and reasonable.

c. Vertical or Sloped ORDC

The current ORDC shape is just and reasonable. A vertical ORDC is just and reasonable. Some RTOs have chosen to allow economic shortages before incorporating a penalty at the $1,000 per MWh level or higher, through a sloped or stepped curve in the shortage portion of the ORDC, which is a just and reasonable approach.[108] Alternatives to the current ORDC shape may be just and reasonable as long as they do not extend the ORDC beyond the minimum reserve requirements. The Market Monitor proposes that the ORDC not include prices other than zero for reserves beyond the defined requirements. Figure 14 depicts an ORDC with a slope in the shortage MW range compared to PJM's proposed ORDC that slopes for MW beyond the minimum reserve requirement.

Figure 14 PJM ORDC and an alternative ORDC sloped for shortage MW only



108 *See* MidContinent ISO, OATT, Schedule 28, Demand Curves for Operating Reserve, Regulating and Spinning; California ISO, OATT, Section 27.1.2.3; Southwest Power Pool, Integrated Marketplace Protocols, v.65.a, Section 4.1.5.2; and New York ISO, Manual 2: Ancillary Services, Section 6.8.

2. Without an Extended ORDC, There Is No Required Capacity Market Offset. With an Extended ORDC, There Is a Required Capacity Market Offset.

a. Under the Market Monitor's proposal there is no required offset.

The Market Monitor's proposed changes to the ORDC would not allow the ORDC to extend beyond the minimum reserve requirement such that energy prices include a scarcity component even when reserves are not short. Therefore, the pervasive impact on energy market revenues under PJM's proposal would be avoided. Without the pervasive impact on energy market revenues, scarcity revenues are not shifted from the capacity market to the energy market. There would be no need for an offset in the short term or the long term to account for the recovery of missing money from the energy market instead of the capacity market.

b. With an extended downward sloping ORDC, there are required changes to the capacity market, including an offset to revenues.

PJM's proposed extended downward sloping ORDC would create scarcity revenues in the energy market that are currently paid in the capacity market. A capacity market offset mechanism and changes to the capacity market VRR are required to return double counted scarcity revenues to customers under PJM's ORDC proposal. The new scarcity revenues that would be created in the energy and reserve markets are the portion of revenues directly attributable to the scarcity price adder to LMP resulting from PJM's ORDC proposal. The new scarcity revenues are not a result, for example, of higher energy prices that are not the direct result of PJM's ORDC. The mechanism for returning the double counted scarcity revenues to load requires that PJM calculate these scarcity rents each day and a final number at the end of the delivery year. Daily capacity payments to generators would be reduced by the daily scarcity revenues. There would be a true up of the scarcity revenues at the end of the delivery year to ensure an accurate calculation. Scarcity revenues returned should never exceed capacity market revenues. If scarcity revenues exceed the capacity market revenues, the extra scarcity revenues would be paid to generators.

There are two options for the true up mechanism for auctions that have not yet cleared. The use of average historical revenues is not a reasonable option because it does not accurately reflect generators' expectations about future revenues in addition to simply missing the increase in revenues associated with PJM's proposed ORDC and PJM's fast start pricing implementation.

The true up mechanism for capacity market auctions for auctions cleared after the implementation of the ORDC could also use the same mechanism to directly return scarcity revenues to customers. This would be the more clear and transparent approach.

The true up mechanism for capacity markets that have not yet cleared could instead include: a forward looking energy and ancillary services offset in the capacity market; a calculation of the energy and ancillary services offset revenues that correctly accounts for dispatch costs and dispatch parameters; a correct definition of the maximum price on the VRR curve equal to 1.5 times net CONE. A forward looking energy and ancillary services offset should: use energy prices from West Hub forward curves with basis differentials to CONE locations based on history; use fuel costs from forward markets with basis differentials to locations based on history; correctly account for the dispatch costs and dispatch parameters of the reference unit.

Under existing capacity market rules, instituted for the 2015/2016 Delivery Year, the maximum price on the VRR curve is the higher of Gross CONE or 1.5 times Net CONE.[109] That rule was implemented in order to prevent the capacity market price from decreasing significantly even when justified by reductions in Net CONE.[110] Thus, under PJM's proposal, even if the EAS revenue were to increase enough to fully reflect the ORDC scarcity revenues, the maximum capacity market price would never fall below Gross

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109 138 FERC ¶ 61,062.

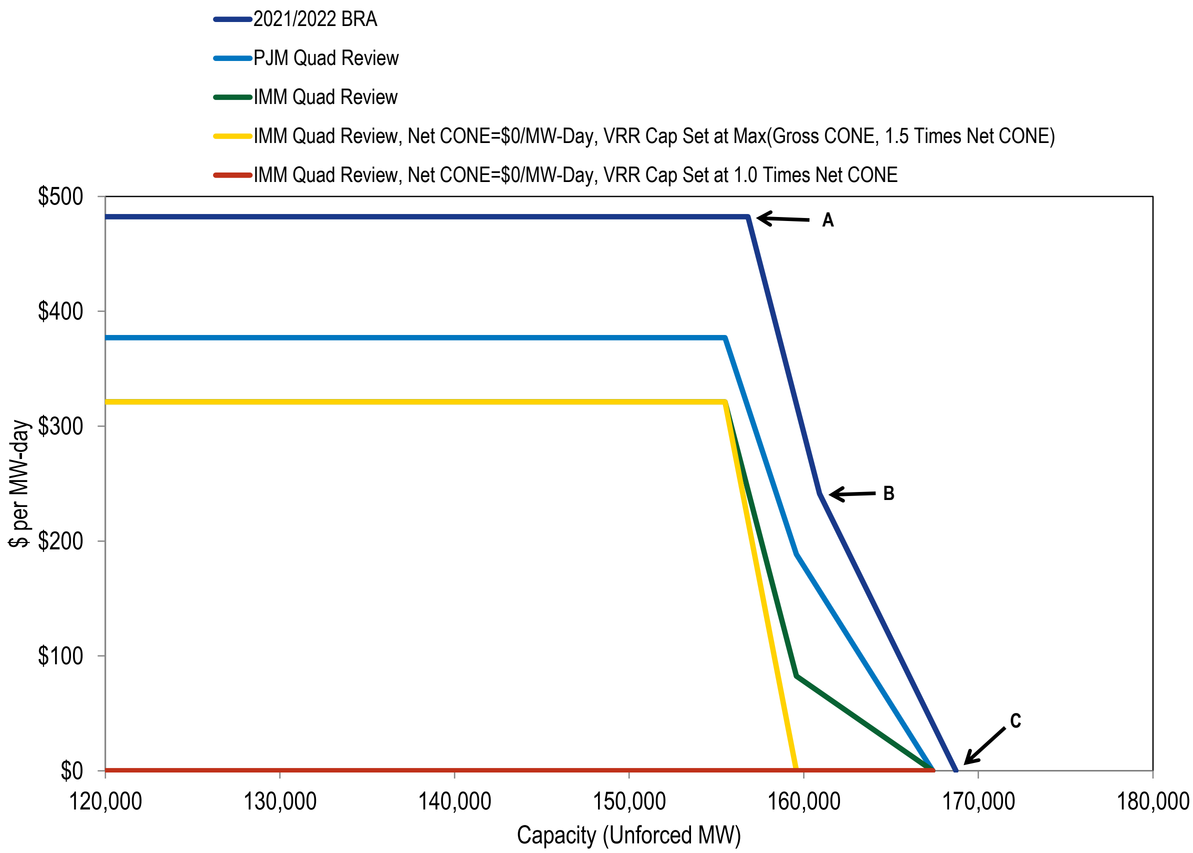
110 PJM Interconnection, L.L.C., Docket No. ER19-105-000, "Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters" (Oct. 12, 2018).

CONE. That rule is inappropriate, given that PJM's ORDC proposal is intended to shift significant revenue from the capacity market to the energy market. If this evolution is ever to lead to the effective elimination of the capacity market, the capacity market price must be allowed to fall, consistent with actual net revenues. The maximum price in the capacity market should be 1.5 times Net CONE and not the higher of Gross CONE and 1.5 times Net CONE.

Under PJM's proposal, the existing shape of the VRR curve would become almost vertical with the maximum price equal to gross CONE under PJM's proposal. Increases to the net energy and ancillary services offset would decrease net CONE to relatively low levels including zero. When Net CONE is low or equal to zero, the capacity market price should be correspondingly low or zero. Under PJM's proposal, the capacity market price would be artificially increased as a result of a rule proposed and implemented under a very different energy pricing regime.

Figure 15 illustrates the issues with the impact of PJM's ORDC proposal on the VRR curve. Starting from the right: VRR curve 1 is the actual VRR curve used to clear the 2021/2022 BRA. VRR curve 2 is PJM's proposed VRR curve in the Quadrennial Review; VRR curve 3 is the Market Monitor's proposed VRR curve in the Quadrennial Review; VRR curve 4 is VRR curve 3 with Net CONE = 0 and the Max price = Gross CONE; VRR curve 5 is VRR curve 3 with Net CONE = 0 and the Max price = 1.5 * Net CONE.

Figure 15 The VRR Curve When Net CONE is $0 per MW-Day



VRR curve 3 has the currently defined shape based on the defined maximum price and inflection points. VRR curve 4 is VRR curve 3 but including a higher EAS offset that reduces Net CONE to zero but has a maximum price equal to Gross CONE. VRR curve 5 is VRR curve 4 with a maximum price equal to 1.5 times Net CONE, which is zero in this case because Net CONE is zero.

Figure 15 illustrates the fact that even when Net CONE is zero and the capacity market price should equal zero, PJM's current rule would result in VRR curve 4 rather than VRR curve 5 and the capacity price would be artificially high as a result.

Point A Price: $\frac{\boldsymbol{Greater\ of(Gross\ CONE, 1.5*Net\ CONE)}}{\boldsymbol{1-Pool\ Wide\ EFORd}}$

Point B Price: $\frac{\boldsymbol{.75*Net\ CONE}}{\boldsymbol{1-Pool\ Wide\ EFORd}}$

Point C Price: $\boldsymbol{\$0.00}$

Point A Quantity: $\boldsymbol{Reliability\ Requirement}\ \frac{(1+IRM-.2\%)}{(1+IRM)}$

Point B Quantity: $\boldsymbol{Reliability\ Requirement}\ \frac{(1+IRM+2.9\%)}{(1+IRM)}$

Point C Quantity: $\boldsymbol{Reliability\ Requirement}\ \frac{(1+IRM+8.8\%)}{(1+IRM)}$

The rule setting the maximum capacity price at the higher of gross CONE or 1.5 times Net CONE was based on the use of historical average net revenues to calculate the EAS offset. The Brattle Report at the time pointed out that historical net revenues could be very high as a result of a very low reserve margin, but the capacity market prices would be low as a result of the associated high energy prices.[111] Brattle also recommended moving to a forward looking EAS offset. Brattle recognized that the asserted need for a maximum price of gross CONE would not exist if there were a forward looking EAS offset. There is no reason to maintain the maximum capacity market price at the artificially high level of gross CONE under PJM's proposal to significantly increase annual energy and ancillary services revenues. This increase in revenues is not the unexpected, episodic increase contemplated by Brattle. There is no reason to maintain the high maximum capacity market price if a forward looking EAS offset were adopted. There is no reason to maintain the high maximum capacity market price if an annual true up were adopted.

3. Consolidate Tier 1 and Tier 2 Synchronized Reserves.

Tier 1 and Tier 2 synchronized reserves are substitutes, so creating a single clearing price market for synchronized reserves is an efficient market design. Structural market power frequently exists in the synchronized reserve market, which had pivotal suppliers in

111 The Brattle Group, "Second Performance Assessment of PJM's Reliability Price Model", August 26, 2011.

58.9 percent of market hours in 2017 and 10.2 percent of market hours in 2018.[112] It is important to strengthen the synchronized reserve market must offer requirement and to impose stronger penalties for nonperformance.

a. Address market power

PJM and the Market Monitor developed a joint proposal to strengthen the synchronized reserve must offer requirement.[113] The March 29th Filing includes changes that will appropriately disallow Market Seller's current ability to withhold reserves from the market by setting an hourly 0 MW synchronized reserve offer. The March 29th Filing also includes stronger language to clarify the synchronized reserve must offer requirement.[114] PJM did not include in the March 29th Filing its joint proposal with the Market Monitor to "automatically calculate reserve offer MW for all generation resources that have offered into the energy market using the ramp rate and economic max submitted for their energy offer."[115] Market power is increased by PJM's current process of deselecting resources for synchronized reserve and lowering resource ramp rates using DGP. These operator interventions to alter resource offers are not just and reasonable and should be disallowed.

A resource's cost to provide synchronized reserve does not exceed its lost opportunity cost due to not providing energy plus any explicit energy costs for synchronized condensing units. No offer margin is necessary. The Market Monitor agrees

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112 Monitoring Analytics, *2018 State of the Market Report for PJM*, Vol. II, Section 10: Ancillary Services at Table 10-15.

113 PJM and Monitoring Analytics, Proposal for Must Offer Requirements, presented to the Energy Price Formation Senior Task Force (October 12, 2018), <*https://pjm.com/-/media/committees-groups/task-forces/epfstf/20181012/20181012-item-07a-sr-must-offer-requirements.ashx*>, accessed May 14, 2019.

114 March 29th Filing, proposed OA § 1.10.1A(j)(i)(1,2).

115 PJM and Monitoring Analytics, Proposal for Must Offer Requirements, presented to the Energy Price Formation Senior Task Force (October 12, 2018), <*https://pjm.com/-/media/committees-groups/task-forces/epfstf/20181012/20181012-item-07a-sr-must-offer-requirements.ashx*>, accessed May 14, 2019 at 2.

with PJM's statement that the $7.50 per MWh offer margin was based on offers that included market power, and thus exceeded efficient, competitive levels.[116] The correct conclusion is that the offer margin should therefore equal zero. The Market Monitor recommends removing the synchronized reserve offer margin entirely, along with the invalid Manual 15 provisions for a maintenance cost that is covered by the energy market offer.[117] The market efficient, just and reasonable, reserve offer is equal to only the product substitution lost opportunity cost calculated by PJM and explicit energy costs of synchronous condensers.

b. Performance penalties

The current synchronized reserve performance penalty, which PJM does not propose to change, is not sufficient. Resources can profitably offer reserves without ever performing during a spinning event, as shown in Table 4.

The immediate past interval (IPI) used to identify the penalty period should be defined as the number of days between spinning events 10 minutes or longer. If only events 10 minutes or longer were considered, the IPI would increase to almost double its current 20 days. Regardless, use of an average IPI is not appropriate. The penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed. That is the only way to capture the actual failure to perform of the resource and the only way to provide an appropriate performance incentive. It is a just and reasonable penalty.

The Market Monitor proposes that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. A penalty based on

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116 March 29th Filing at 46.

117 *See* OA Section § 1.10.1A(j)(i)(3) and PJM Manual 15: Cost Development Guidelines at Sections 4.7 and 5.7.

resource specific response is just and reasonable. The Market Monitor also proposes similar penalties for nonsynchronized reserve and secondary reserve.

4. Reserves in the Day-ahead Market.

If reserves are to be included in the day-ahead market, the Market Monitor proposes limited changes to the rules governing uplift payments, including lost opportunity cost payments. All that is required to support an efficient market is to account for all revenues and losses that result from the joint energy and reserve dispatch on a daily 24-hour basis. This approach is simple, transparent, just and reasonable. Under the Market Monitor's proposal resources are not expected to provide energy and reserves at a loss, as is the case today.

5. Demand Response.

There should be no cap on demand response participation in the reserve markets. Demand response participation in reserve markets should not be limited in any way. Demand response resources receive the same capacity payments but have different obligation to provide energy and reserves as any other resource. Demand response resources participating in the capacity market do not have an energy or reserve must offer requirement. To the extent demand response resources have stated availability within 10 or 30 minutes, they should be counted toward the 10 or 30 minute reserve requirements. Allowing demand response to fully participate in the markets with the same rights and obligations as other resources is just and reasonable.[118]

II. CONCLUSION

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

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118 *See Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 at paras. 14, 15, 84.

Respectfully submitted,

Jeffrey W. Mayes

Joseph E. Bowring
Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8051
joseph.bowring@monitoringanalytics.com

Catherine Tyler
Senior Economist
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8050
catherine.tyler@monitoringanalytics.com

Jeffrey W. Mayes
General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

Dated: May 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 May, 2019.

Jeffrey W. Mayes
General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

ATTACHMENT A

Monitoring Analytics

Winter Peak Price and Uplift Analysis: January 2019

The Independent Market Monitor for PJM

May 13, 2019

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Introduction

PJM experienced a winter peak period in January 2019 marked by moderate prices, reliability, and resilience in response to forced outages and fuel supply disruptions. A smoother winter peak in 2019 compared to past winters was the result of an expanded natural gas supply in the PJM region and a reduction in forced outage rates for natural gas generation. Unlike recent winters, 2014 and 2018, the cost of natural gas fired generation remained below the cost of oil fired generation.

In January, prices rose consistent with an increased cost of fuel and temporary scarcity conditions on three days. PJM notes that reserve prices were at or near zero for 19 of 24 hours on January 31, 2019.[1] The IMM counts 72 five minute intervals of nonzero reserve pricing (six hours), or 18 of 24 hours of pricing at zero. These zero reserve prices were consistent with supply and demand conditions. For example, during the morning ramping period between 2:00 and 8:00 AM, steam generators either self scheduled energy or began producing energy several hours prior to their day-ahead market commitments, shifting out the supply of zero cost reserves. Operator actions, including Tier 1 reserve biasing to commit condensing combustion turbines for synchronized reserves, had limited effects on prices.

Uplift payments were moderate and revealed no underlying problems with price formation. Uplift could have been further reduced by implementing recommendations to simplify uplift payments and eliminate payments to resources that do not follow PJM's instructions.

Supply and Demand

Load

PJM load in January 2019 was similar to the previous five years. Table 1 presents total real-time demand for January of 2014 through 2019.

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1 *See* "Reliability, Fuel Supply Strong in PJM During 2018-2019 Winter," PJM News Release, March 18, 2019.

Table 1 January real-time load and real-time load plus exports: 2014 to 2019

	PJM Real-Time Demand (MWh)		Year-to-Year Change (%)	
January	Load	Load Plus Exports	Load	Load Plus Exports
2014	77,948,987	81,474,795	NA	NA
2015	74,259,031	78,225,506	(4.7%)	(4.0%)
2016	71,525,305	74,358,276	(3.7%)	(4.9%)
2017	68,134,794	71,916,580	(4.7%)	(3.3%)
2018	75,338,592	78,341,618	10.6%	8.9%
2019	72,405,320	76,591,469	(3.9%)	(2.2%)

The winter peak hour load in 2019, occurring at 8:00 AM on January 31, 2019, was the highest since 2015, and only 1.6 percent lower than 2014. Table 2 presents the hourly winter peak load values for 2014 through 2019. The winter peak load for 2018 and 2019 both increased from the previous year.

Table 2 Winter peak loads: 2014 to 2019

		Hour Ending	PJM Peak Demand (MWh)		Peak Load Annual Change	
Year	Date	(EPT)	Load	Load Plus Export	(MWh)	(%)
2014	Tue, January 07	19	136,932	140,799	NA	NA
2015	Fri, February 20	8	139,647	144,850	2,715	2.0%
2016	Tue, January 19	8	126,818	131,506	(12,830)	(9.2%)
2017	Mon, January 09	8	124,210	129,726	(2,608)	(2.1%)
2018	Fri, January 05	19	133,851	137,942	9,641	7.8%
2019	Thu, January 31	8	134,060	138,481	209	0.2%

Table 1 and Table 2 include gross exports. Net interchange, (imports minus exports) was consistently negative during January 2019 and at the time of the January 31, 2019, winter peak, PJM also exported more power than it imported.

Available Supply

Although January loads were comparable to prior years, there was enough supply to meet demand at lower prices than previous winters.

Capacity

PJM installed capacity was 183,386.2 at June 1, 2018. Table 3 shows net capacity changes since 2007/2008. Installed capacity was lower on June 1, 2018, than on June 1, 2013, and on June 1, 2014, but higher than for June 1, 2015 through 2017.

Table 3 Generation capacity changes: 2007/2008 to 2018/2019

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	167.8	1,074.8
2017/2018	183,100.0	5,656.4	4.0	331.5	0.0	(1,442.0)	(220.9)	4,351.6	133.0	286.2
2018/2019	183,386.2									
Total		23,479.1	971.0	6,431.6	18,109.0	3,545.5	(2,519.2)	31,959.6	3,369.0	19,726.8

Table 4 shows the calculated RPM reserve margin and reserves in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021. Table 4 accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the final peak load forecast for the given delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2019, and June 1, 2020, do not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margins for June 1, 2019, and June 1, 2020, account for projected replacement capacity using cleared buy bids by applying the historical buy bid utilization rate.

Table 4 RPM reserve margin: June 1, 2016 to June 1, 2021

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM Percent	Reserve Margin in Excess of IRM ICAP (MW)	Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	164,777.8	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	175,444.8	25.9%	9.9%	13,788.1	1,616.1	24.7%
01-Jun-20	165,943.4	152,245.4	12,065.2	558.0	139,622.2	15.9%	5.97%	176,479.2	26.4%	10.5%	14,657.1	3,446.6	23.8%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

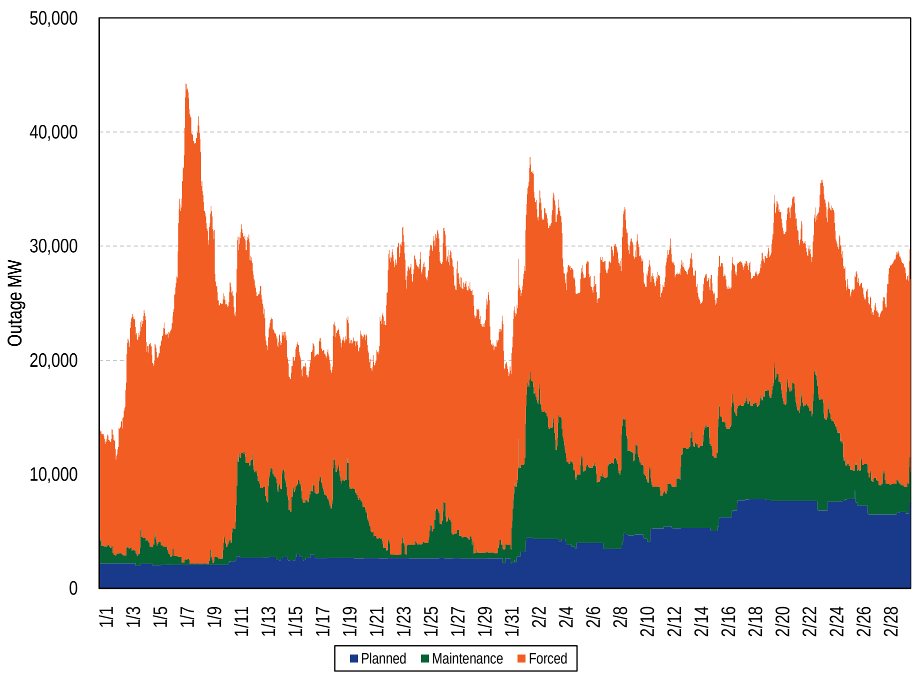
Generator Performance

Figure 1, Figure 2, Figure 3 and Figure 4 show the hourly outages for January and February 2014 and January and February 2019 by type of outage and primary fuel.[2] In

2 The generator performance analysis includes all PJM resources that had energy market offers during the relevant time period and for which there are data in the PJM generator availability

2014, peak system outages of 44,248 MW occurred on January 7, hour beginning 0700 EST. In 2019, peak system outages of 27,865 MW occurred on February 27, hour beginning 0800. The reduction in forced outages from 2014 to 2019 was the result of a combination of factors including unit retirements and improved unit performance to meet capacity performance requirements.[3] There were significantly fewer outages for natural gas fired capacity in 2019 than in 2014. The reduction in peak January and February outages between 2014 and 2019 was much greater for natural gas-fired generation than for coal-fired or nuclear generation.

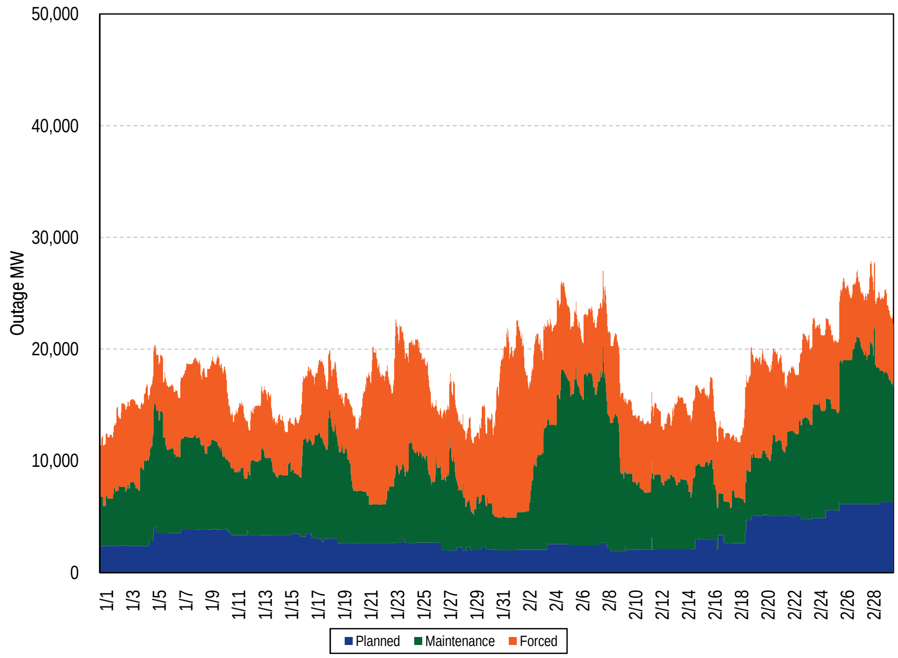
Figure 1 Outages by type: January through February, 2014



data systems (GADS) database. Data was downloaded from the PJM GADS database on March 28, 2019.

3 In 2015, 2,177 MW of CT capacity and 7,065 MW of coal capacity retired.

Figure 2 Outages by type: January through February, 2019



In January through February 2014, the maximum outage MW in a single hour from natural gas units was 25,840 MW, from coal units was 21,203 MW, and from nuclear units was 4,155 MW. In January through February 2019, the maximum outage MW from natural gas plants was 9,756 MW, from coal units was 17,651 MW, and from nuclear units was 4,875 MW.

Figure 3 Outages by primary fuel: January through February, 2014[4]

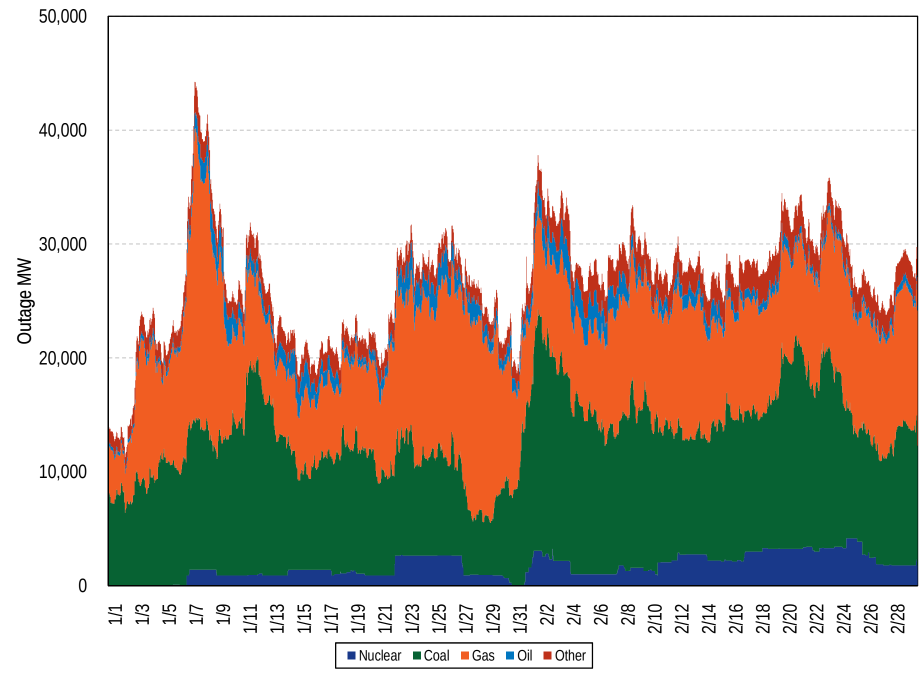
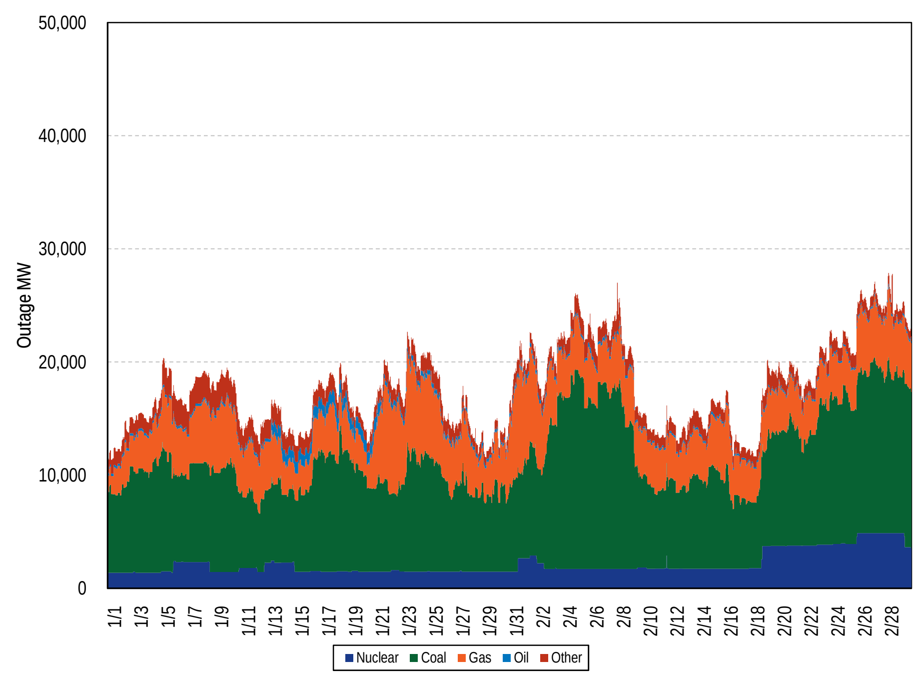


Figure 4 Outages by primary fuel: January through February, 2019



4 Oil includes oil, distillate oil, and kerosene. Other includes other gas, other liquid, other solid, waste heat, water, and wood.

Offered Supply

Figure 5 shows, for each hour on January 31, 2019, the available committed installed capacity in PJM (installed capacity (ICAP) committed in the capacity market minus total reported outage MW), the average hourly load used in LPC for pricing, and the available committed ICAP net of load. Figure 5 shows that, on January 31, 2019, PJM had a minimum of 24,100 MW of available (online and offline) committed capacity above the load in every hour. The outage MW used in the calculation of the available ICAP are reported outages from committed capacity resources and uncommitted capacity resources. Therefore, the amount of available committed ICAP net of load is a conservatively low estimate, and is likely higher than the values shown in Figure 5.

Figure 5 Available committed installed capacity, and hourly average load: January 31, 2018

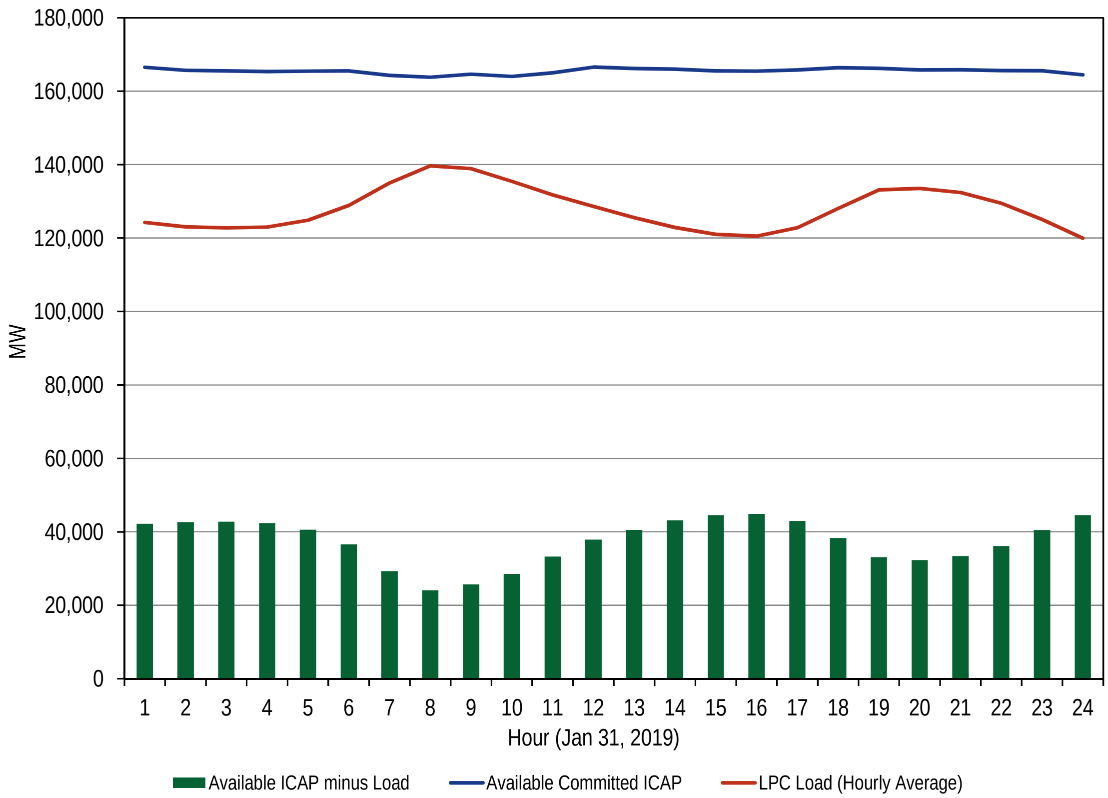
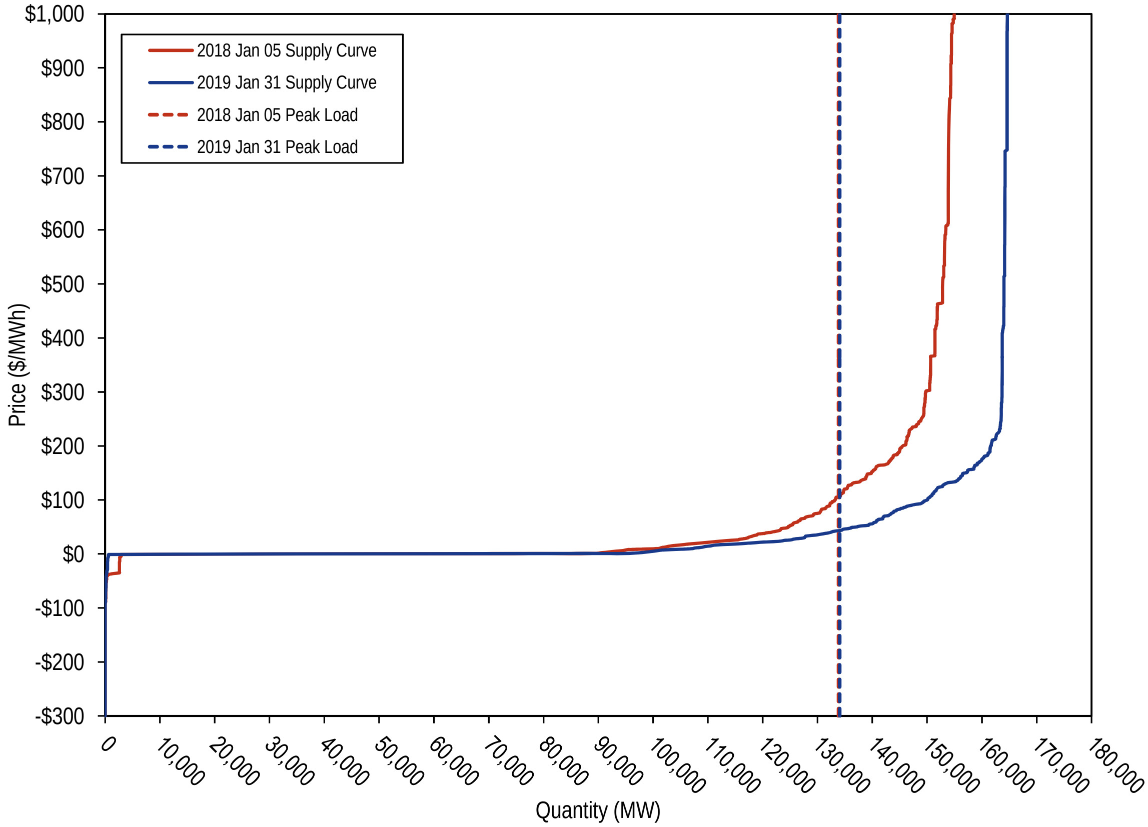


Figure 6 shows the average hourly real-time supply and load for winter peaks, January 5, 2018, and January 31, 2019. This figure reflects actual available MW from units that are online or available to generate power within one hour including start-up and notification time, and ramp limits.

Figure 6 Average hourly real-time supply curves: January 5, 2018 and January 31, 2019



Natural Gas Market Conditions

Natural gas prices in PJM were below the cost of oil during the 2018/2019 winter unlike the 2017/2018 winter.

The increase in available power supply at lower prices in 2019 than in 2014 was in part a result of increased natural gas capacity and supply in the PJM region and in part a result of somewhat different weather conditions in 2019.[5]

The demand in PJM states for natural gas for power production in January 2019 was higher than in any winter month since January 2014. Figure 7 shows natural gas usage in

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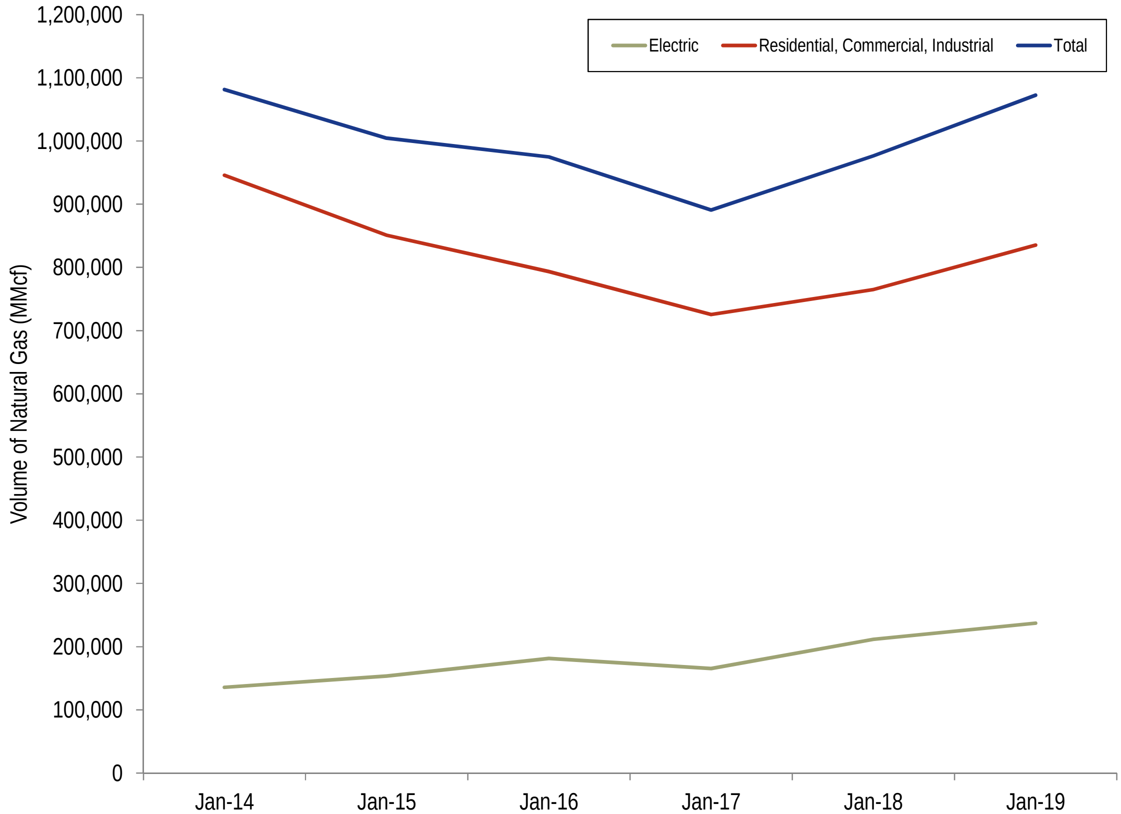
[5] *See* Energy Information Administration, "Increases in natural gas production from Appalachia affect natural gas flows," Today in Energy (March 21, 2019). <https://www.eia.gov/todayinenergy/detail.php?id=38652&src=email#>. See also <https://www.ferc.gov/legal/staff-reports/2018/dec-energy-infrastructure.pdf>. See also Energy Information Administration, Natural Gas Consumption by End Use (accessed April 23, 2019). <https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm>. See also Energy Information Administration, Natural Gas Gross Withdraws and Production (accessed April 23, 2019). <https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm>.

the PJM states for power production and all other uses. The demand for natural gas for power production was 237,175 MMCF in January 2019 and 135,685 MMCF in January 2014, a 175 percent increase.[6] The demand for natural gas for power production was 22 percent of total demand for natural gas in PJM states in January 2019.

Figure 7 January Natural gas consumption in the PJM states: 2014 through 2019[7]



Natural gas prices in PJM were above oil prices on 16 days during the 2017/2018 winter. Figure 8 shows daily natural gas prices in PJM and Henry Hub, and the NY Harbor ultra low sulfur diesel (ULSD) price.

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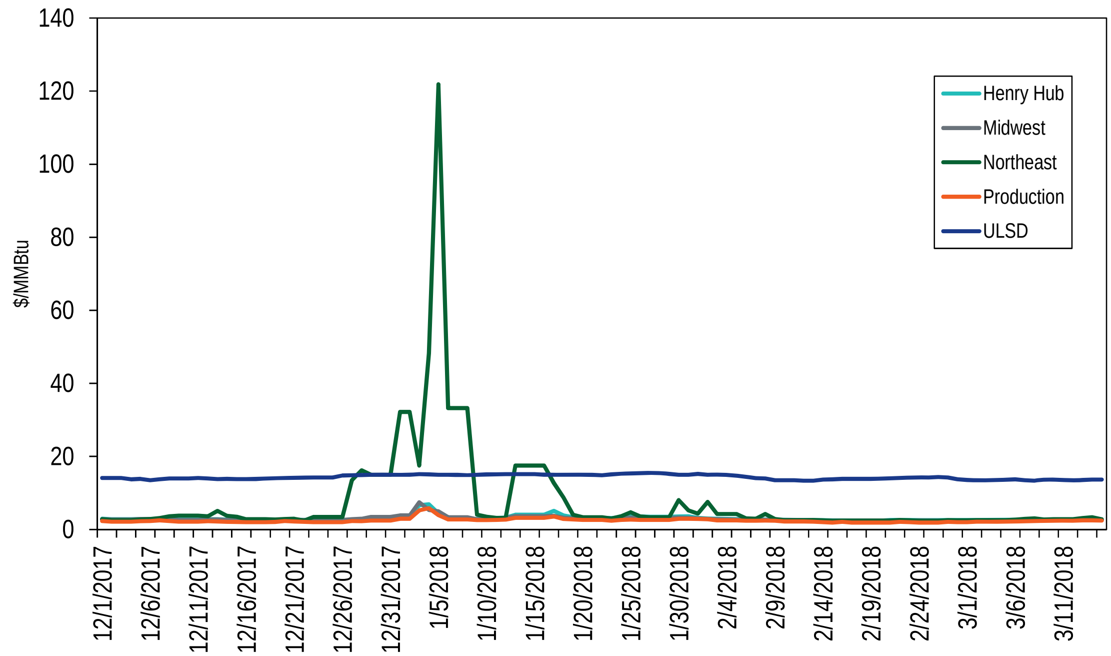
6 Energy Information administration, Natural Gas Consumption by end user (accessed April 23, 2019) <https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SIL_m.htm>.

7 2018 State of the Market Report for PJM, Vol. 1, Introduction: PJM Market Background.

Figure 8 Winter natural gas prices and ULSD price: December 1, 2017 through March 11, 2018



Natural gas prices in PJM were never above oil prices during the 2018/2019 winter. Figure 9 shows the daily natural gas prices in PJM and Henry Hub, and the NY Harbor ULSD price.

Figure 9 Winter natural gas prices and ULSD price: December 1, 2018 through March 11, 2019

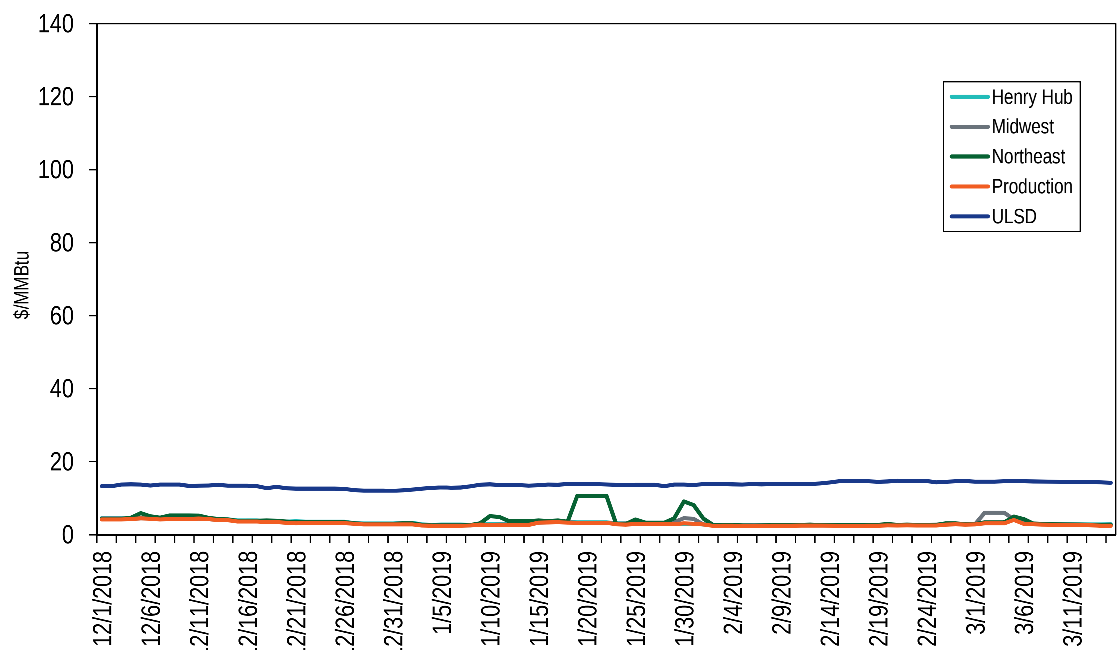


Figure 10 shows the monthly average natural gas prices in PJM and Henry Hub, and the NY Harbor ULSD price in January 2014 through 2019.

Figure 10 January average natural gas prices and ULSD price: 2014 through 2019

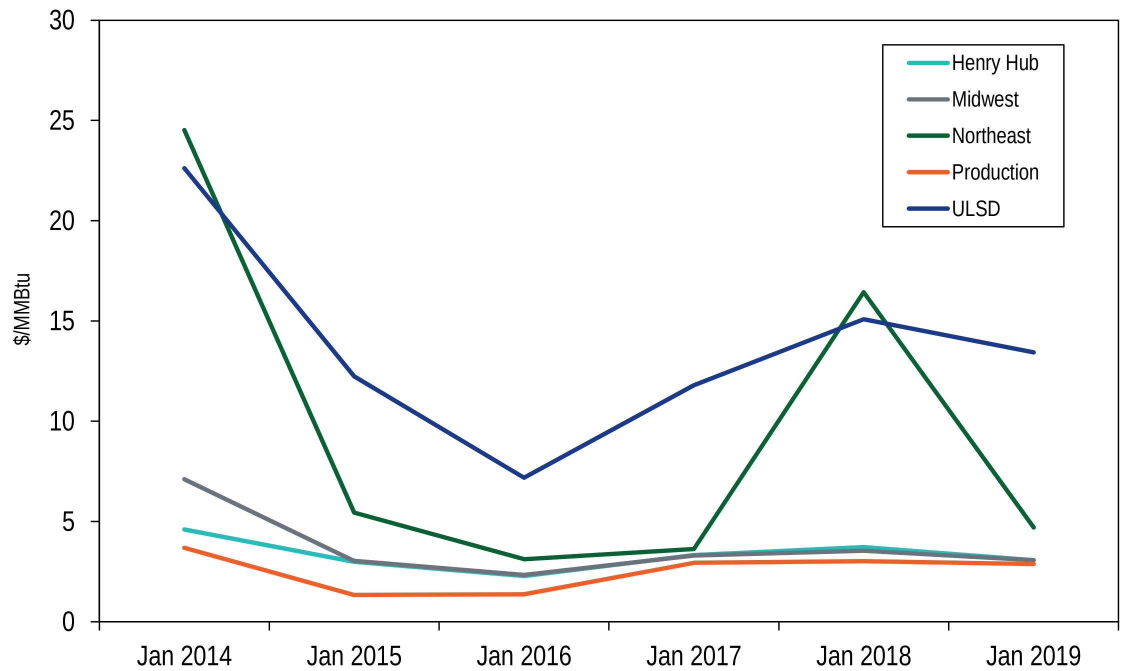


Table 5 shows the average spread between natural gas prices in the eastern region of PJM (market area) and Marcellus shale gas prices (production area) for days in which the prices in the eastern region of PJM were below $5 per MMBtu. Table 5 shows that on average in 2018, the spread between the market area and production area was $0.80 per MMBtu and in 2019 the spread was reduced to $0.34 per MMBtu. This is consistent with increased capacity to move gas from the production area into the market area.

Table 5 Natural gas price spread between PJM eastern region and Marcellus shale production area: December 1 through March 15, 2018 and 2019

Month	2018 Spread ($/MMBtu)	2019 Spread ($/MMBtu)
December	0.99	0.25
January	0.90	0.55
February	0.72	0.26
March	0.51	0.29
Average	0.80	0.34

Increased flow from the gas production region to the load centers of PJM supports reliability and resilience in PJM. The natural gas market conditions in January 2019 allowed PJM to meet winter peak load with natural gas fired generation, instead of relying on oil fired generation, as it did in January 2018. The economic and reliable availability of natural gas fired generation contributed to PJM market conditions that were not as tight at the 2019 winter peak compared to previous winter peaks.

Reserves

Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[8] Primary reserves are made up of resources (synchronized and nonsynchronized) that can provide energy within 10 minutes.

Synchronized reserves consist of tier 1 and tier 2 synchronized reserves. Tier 1 reserves are provided by online resources at zero cost, tier 1 reserves are equal to the 10 minute ramp capability provided by resources from the economic dispatch point provided by PJM. Tier 2 reserves are provided by online resources at a cost. Tier 2 reserves are provided by online resources that are ramped down from their economic dispatch point in order to provide reserves. These resources incur an opportunity cost of not providing energy. Tier 2 reserves are also provided by resources that can operate in condensing mode that incur condensing costs and opportunity costs.

Tier 1 and Tier 2 Reserves

PJM claims that low reserve prices on January 31, 2019, demonstrate a market design flaw necessitating a downward sloping Operating Reserve Demand Curve (ORDC) at levels greater than the synchronized and primary reserve requirements.[9] However, reserve prices were consistent with supply and demand conditions. The market functioned efficiently. There was no evidence of a market design problem on January 31, 2019.

Figure 11 shows how PJM satisfied the synchronized and primary reserve requirements in each five minute interval on January 31, 2019. Following the synchronized reserve shortage at 1:30 AM, PJM operators committed 11 hydro and combustion turbine units to provide tier 2 synchronized reserves in condensing mode, increasing the level of synchronized reserves. The increased level of scheduled synchronized reserves is shown in the green area in Figure 11. Several large units also self scheduled or came online several hours prior to their commitment in the early morning hours, increasing the available tier 1 synchronized reserve. The increased level of tier 1 reserves is shown in the gray area in Figure 11. As a result, for almost all intervals between 2:00 AM and 6:00 AM, zero cost reserves fully satisfied the synchronized reserve requirement. When tier 1 exceeds the synchronized reserve requirement, the gray area in Figure 11 is above the yellow line, and the supply curve for synchronized reserves meets the requirement at a

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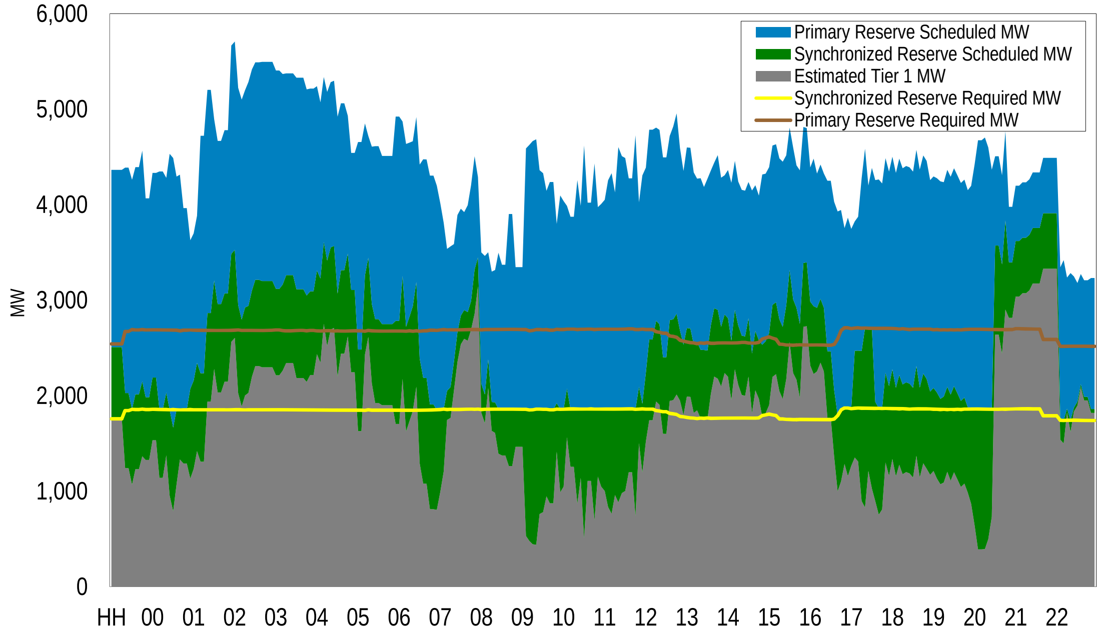
[8] See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 37 (Dec. 10, 2018).

[9] See Market 29th Filing at 20-21.

price of zero. The large amount of Tier 1 reserves online resulted from market participant decisions, not from operator actions.

Figure 11 Components of primary reserve: January 31, 2019



Measuring Reserves

PJM adjusts the calculated level of reserves by overriding certain unit availability and capacity inputs, biasing forecast load, and biasing calculated tier 1 reserve MW. PJM imposes additional eligibility criteria on units to qualify as reserves, criteria that are ad hoc and are not transparent. PJM's adjustments include changes to submitted resource ramp rates (DGP), deselection of resources, and changes to resource output limits. These are the same adjustments described by PJM in the Price Formation Filing.[10] The result of the adjustments is a lower measured level of reserves than actual available reserves.

Figure 12 shows the amount of offline reserves on January 31, 2019, based on the RT SCED solutions using all available supply and the submitted parameters for the resources. The figure shows the amount of available capacity from offline resources based on their time to start. During the peak hour (HE08), PJM had an average of 508 MW of 10 minutes offline reserves, 14,785 MW of 30 minutes offline reserves, 15,384 MW of 60 minutes offline reserves and 18,490 MW of 120 minutes offline reserves.

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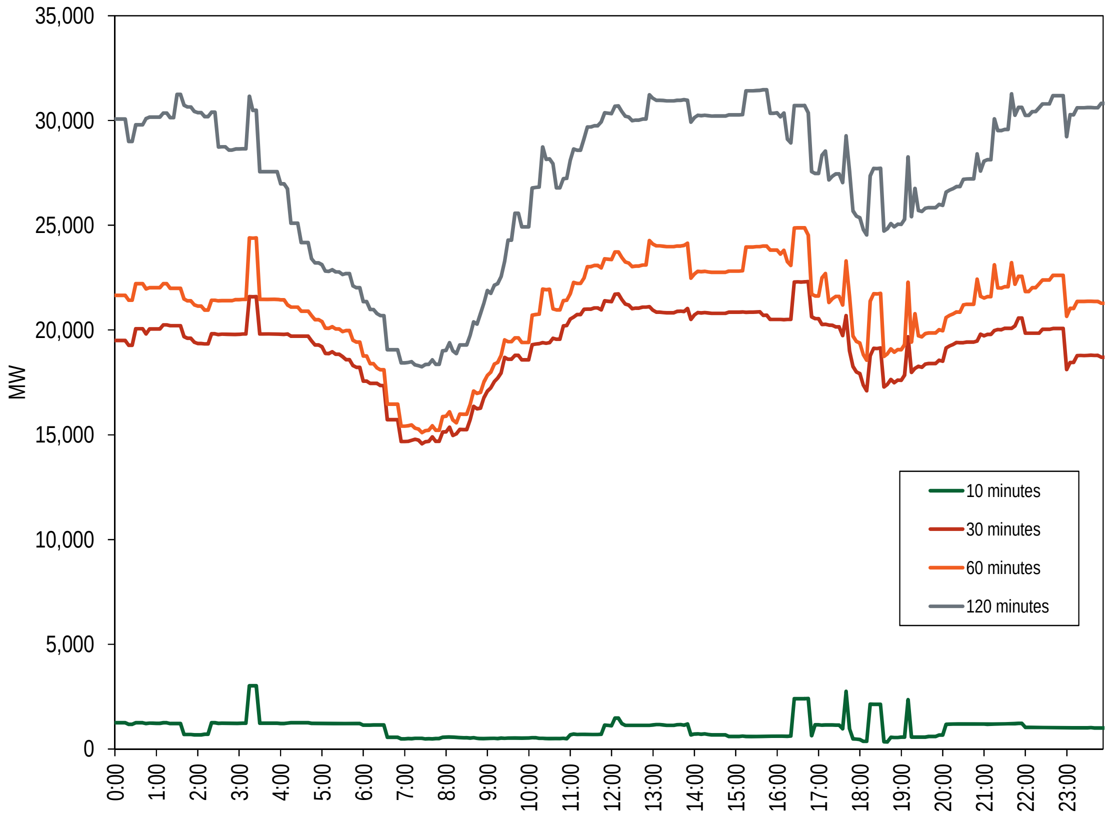
10 *See* Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C., Docket No. 19-58 (March 29, 2019) ("Price Formation Filing") at Pilong Affidavit, P. 24.

Figure 12 RT SCED Reserves: January 31, 2019



PJM does not include all 10 minute synchronized reserves in the calculation of synchronized reserves. There are several actions that PJM takes that reduce the amount of 10 minute synchronized reserves that SCED uses to clear the synchronized reserve market and determine shortage.

PJM makes unilateral and nontransparent determinations of which resources can provide synchronized reserves. PJM dispatchers can deselect units based on the units' commitment reason. For example, PJM can deselect units that are not following PJM's dispatch instruction according to PJM criteria, certain self scheduled units, certain regulating units, certain manually committed units. PJM also adjusts the amount of ramp available from each resource by multiplying the ramp rate offered by the unit times the DGP (degree of generator performance).

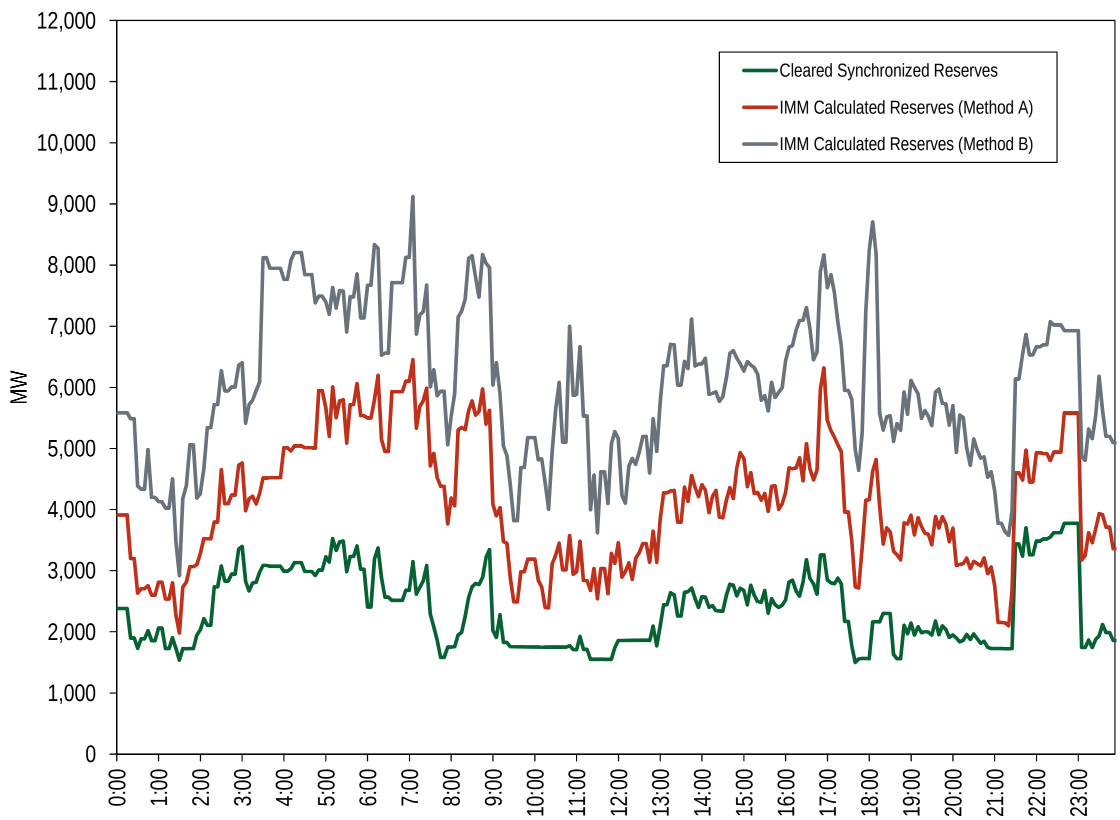
Figure 13 shows the amount of synchronized reserves cleared by PJM and the amount of synchronized reserves calculated by the IMM on January 31, 2019, based on the RT SCED solutions. The IMM uses two methods, A and B, to demonstrate the effects of adjustments to the synchronized reserve measurement process.

Method A: Nuclear, wind, landfill, hydro and solar units, and units testing or released (shutting down) are deselected. PJM's deselections are ignored in Method A.

Method B: Method A deselection plus units' maximum output capability is based on the emergency maximum, not the spinning maximum; units' 10 minute reserve capability is calculated using the unit's submitted ramp rate, not PJM's adjusted DGP ramp rate.

During the peak hour (HE08), PJM cleared an average of 2,275 MW of synchronized reserves, the IMM method A resulted in 5,008 MW and the IMM method B resulted in 6,558. There was one interval of shortage pricing on January 31 (interval 01:30), on that interval PJM cleared 1,538 MW of synchronized reserves, the IMM method A resulted in 1,982 MW and the IMM method B resulted in 2,917 MW. Based on both methods used by the IMM, PJM was not short.

Figure 13 RT SCED calculated synchronized reserves: January 31, 2019



The IMM and PJM agreed to the removal of unit specific deselection for reserves in the Energy Price Formation Senior Task Force stakeholder process.[11] But PJM did not include it in the Price Formation Filing.

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11 "The tariff should include a requirement that all generation capacity resources with a capacity commitment for the operating day offer all available reserve capability at all times, whether online or offline. Generation resources without a capacity commitment that provide an offer in the Energy Market will have that offer serve as a joint offer for energy and

Low reserve prices on January 31, 2019, were consistent with supply and demand fundamentals include a more than adequate supply of reserves. Low reserve prices on January 31, 2019, do not indicate a market design flaw.

Spinning events

There were three spinning events in January including two on January 31. Recovery times were good.

Table 6 Spinning events [12]

Event Date	Event Cause	Start Time	Duration (Min)	Tier 1 Estimate MW	Tier 1 Response MW	Settled Tier 1 MW Increase	Tier 2 Assigned MW
22-Jan-19	Unit trip	22:30	8	2421.1	875	1,967.3	14.4
31-Jan-19	Unit trip	1:26	5	1139.5	561.7	1,498.1	715.5
31-Jan-19	Unit trip	9:26	8	1609.8	541.5	2,383.4	325.8

During all three January 2019 spinning events, total Tier 1 estimated plus Tier 2 assigned synchronized reserve exceeded the requirement. Total synchronized reserve response exceeded the loss of generation which triggered the event. PJM recovered from each spinning event in less than 10 minutes. Table 6 shows: market software estimated tier 1 MW prior to the spinning event; the response MW calculated by the market software for resources included in the initial tier 1 estimate; settled tier 1 MW based on metered output and assigned tier 2 MW. PJM's calculation of the tier 1 response (Tier 1 Response MW in Table 6) is understated because it includes the response only from units for which RT SCED estimated a response. The OATT requires that PJM pay all tier 1 response MW. PJM analyzes all tier 1 response including response from resources that were not a part of the RT SCED estimate for settlements purposes. The actual credited response exceeded the reported Tier 1 Response MW by a significant margin for each of the three events in Table 6. The actual credited response exceeded the estimated MW in

reserves. The tariff should include a clear statement of this must offer requirement. The current statement is not clear enough." See: PJM and Monitoring Analytics, Proposal for Must Offer Requirements, presented to the Energy Price Formation Senior Task Force (October 12, 2018), <https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181012/20181012-item-07a-sr-must-offer-requirements.ashx> >.

[12] Tier 1 Estimate MW, Tier 1 Response MW, and Tier 2 Assigned MW values are publicly available on the PJM website under Operating Committee, Executive Operations Report. Note that tier 2 response is not measured or meaningful for events less than 10 minutes.

two of the three events in Table 6. The Settled Tier 1 MW includes all MW which responded and were paid based on the actual response.[13]

Prices

LMP

Energy prices reflect the supply/demand fundamentals. Prices in January 2019 were not too low. Prices in January 2019 were not too high. The same is true for energy prices in January from 2014 through 2019. Table 7 shows the PJM load weighted average LMP for January for each year since 2014. Higher prices occurred in January 2014 and 2018 as a result of high gas prices and particularly natural gas prices greater than oil prices.

Table 7 PJM real-time load-weighted average LMP: January, 2014 through 2019

January Year	LMP
2014	$126.76
2015	$38.42
2016	$30.15
2017	$32.25
2018	$81.95
2019	$32.14

Table 8 shows the components of LMP for January 2014 through 2019.

13 The 2019 Quarterly State of the Market Report for PJM: January through March (Table 10-21, p. 473) includes the PJM reported MW of response but not the settled MW of response.

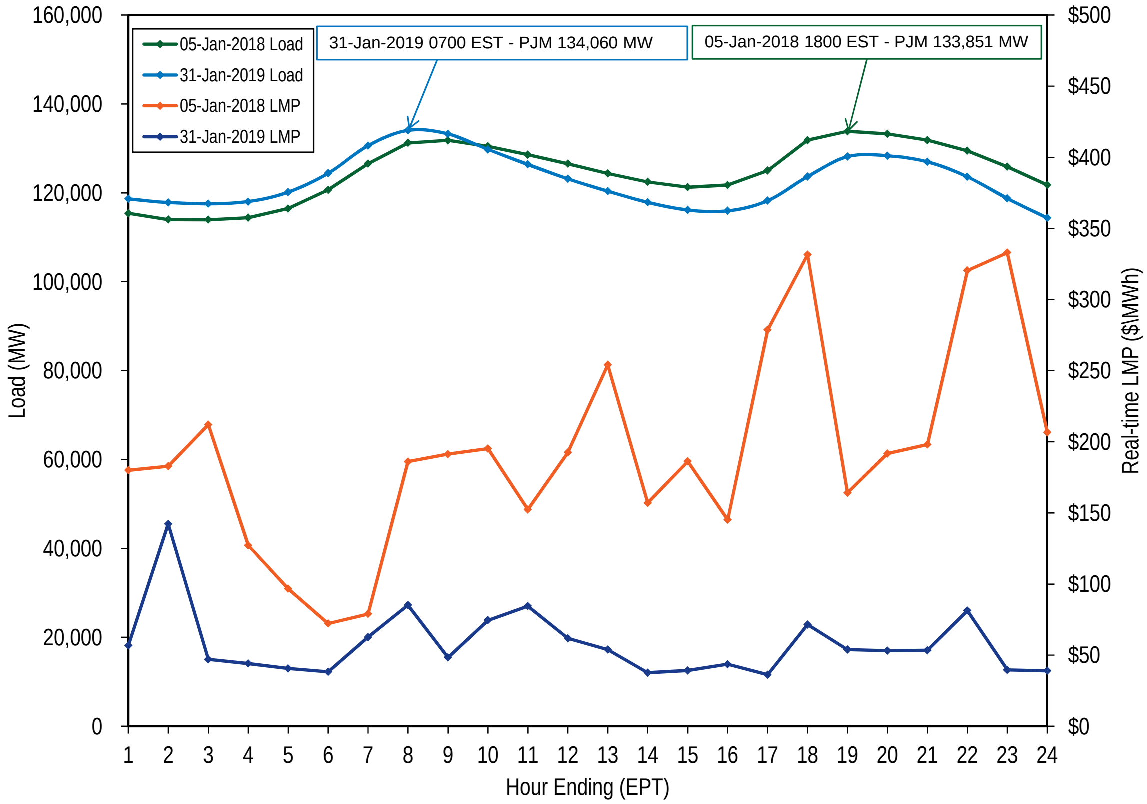
Table 8 Components of PJM real-time LMP for: January, 2014 through 2019

Component	Jan 2014	Jan 2015	Jan 2016	Jan 2017	Jan 2018	Jan 2019
Gas	$43.83	$10.40	$7.34	$14.13	$32.96	$15.89
Coal	$18.76	$19.65	$15.66	$9.65	$5.57	$7.56
Markup	$6.83	$0.61	$0.76	$4.43	$14.99	$4.42
VOM	$3.72	$2.37	$2.07	$1.43	$1.49	$1.77
Increase Generation Adder	$2.48	$0.27	$0.25	$0.15	$2.47	$0.66
LPA Rounding Difference	($0.48)	$0.36	$0.22	$0.31	$1.78	$0.64
Ancillary Service Redispatch Cost	($0.06)	$0.78	$0.47	$0.41	$1.36	$0.59
Scarcity Adder	$1.00	$0.00	$0.00	$0.00	$0.00	$0.26
CO2 Cost	$0.11	$0.20	$0.05	$0.12	$0.06	$0.25
Opportunity Cost Adder	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05
NA	$6.54	$0.72	$1.77	$0.05	$4.21	$0.02
Oil	$18.51	$1.51	$0.86	$1.00	$16.68	$0.02
Renewable Energy Credits	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
Landfill Gas	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
Ten Percent Adder	$6.24	$1.41	$0.02	$0.01	$0.09	$0.01
Other	$0.03	$0.11	$0.23	$0.03	$0.06	$0.00
Market-to-Market Adder	$0.02	$0.00	$0.01	$0.00	$0.02	$0.00
SO2 Cost	$0.01	$0.01	$0.09	$0.06	$0.02	$0.00
NOx Cost	$0.18	$0.02	$0.46	$0.45	$0.14	$0.00
Uranium	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Municipal Waste	$0.10	$0.01	$0.01	$0.02	$0.86	$0.00
FMU Adder	$1.47	$0.00	$0.00	$0.00	$0.00	$0.00
Wind	($0.11)	$0.02	($0.06)	$0.04	($0.01)	$0.00
Emergency DR Adder	$18.29	$0.00	$0.00	$0.00	$0.00	$0.00
LPA-SCED Differential	($0.01)	$0.00	($0.01)	($0.03)	($0.06)	($0.00)
Decrease Generation Adder	($0.69)	($0.03)	($0.03)	($0.02)	($0.75)	($0.02)
Total	$126.76	$38.42	$30.15	$32.25	$81.95	$32.14

The largest component of LMP is the cost of fuel. The cost of natural gas was the largest component of LMP in January 2014, 2017, 2018, and 2019. The cost of gas was a significantly higher contributor to LMP in January 2014 and January 2018. The cost of oil was a significantly higher contributor to LMP in January 2014 and January 2018.

Figure 14 presents the loads and LMPs for the peak days: January 5, 2018, and January 31, 2019. The average real-time LMP for the January 5, 2018, peak load hour was $164.20 per MWh and for the January 31, 2019, peak load hour was $85.20 per MWh. The winter 2018 peak hour LMP reflects oil as the marginal fuel, while the 2019 winter peak LMP reflects gas as the marginal fuel.

Figure 14 Peak-load day comparison: Friday, January 5, 2018 and Thursday, January 31, 2019

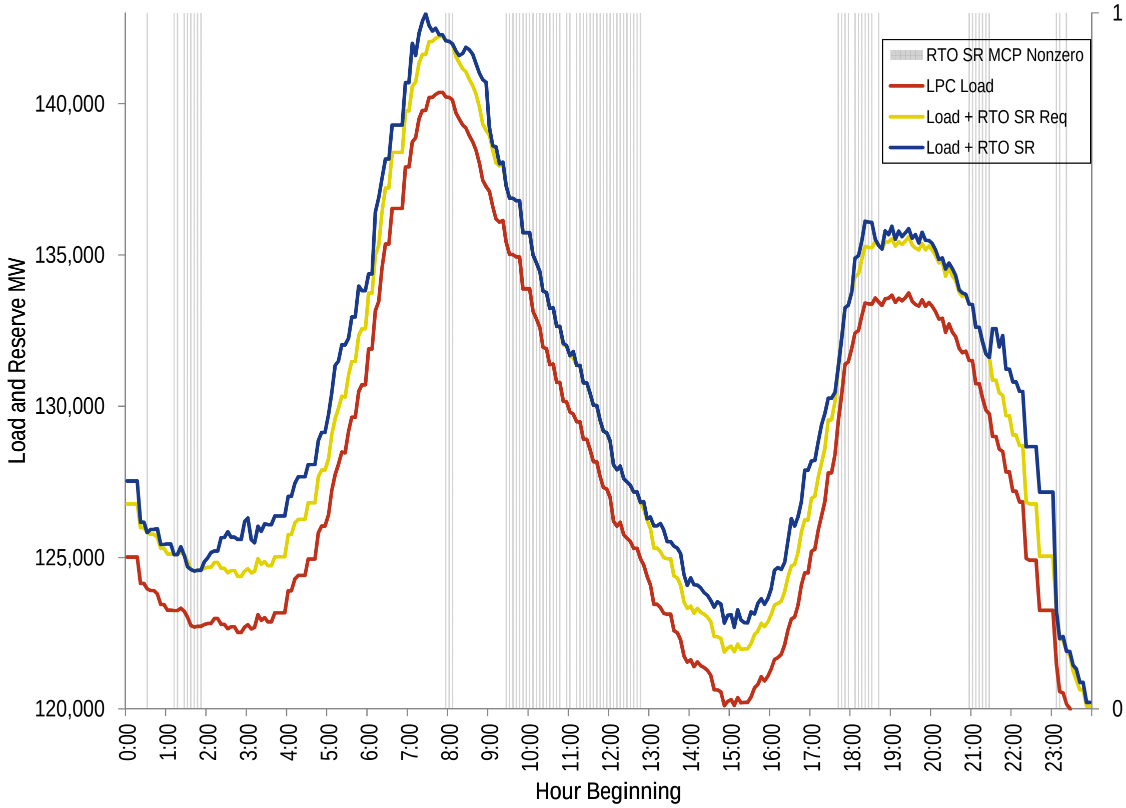


Reserve Prices

PJM reserve prices on January 31, 2019, began higher than usual during the early hours of the day. Load was high for the middle of the night, exceeding 120 GW. A shortage event at 1:30 AM resulted in shortage prices. Tier 1 synchronized reserves averaged 2,028 MW from 2:00 to 8:00 AM, in excess of the reserve requirement, and the price of reserves was zero as a result. Tier 1 levels declined after the morning peak, and reserve prices returned to positive values for much of the midday and approaching the evening peak.

Figure 15 shows the five minute load, load plus the synchronized reserve requirement, and load plus synchronized reserves, with the five minute intervals with a nonzero synchronized reserve price highlighted by the gray vertical lines.

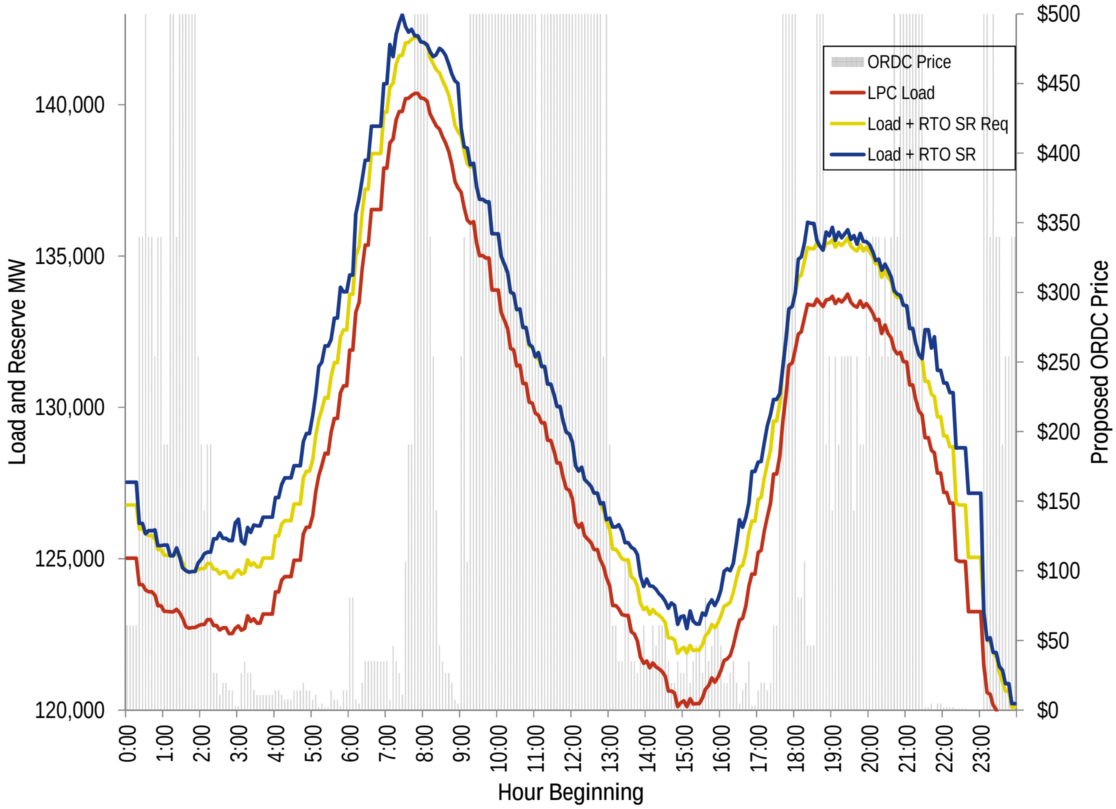
Figure 15 PJM five minute load and synchronized reserve: January 31, 2019



A price of zero, from hours ending 2:00 through 8:00, leading up to the winter peak hour may seem counterintuitive but it was largely a result of units self scheduling in anticipation of peak prices.

Figure 16 shows the price PJM's proposed ORDC would assign given the level of reserves for each five minute interval on January 31, 2019, along with the five minute load, load plus the synchronized reserve requirement, and load plus synchronized reserves.

Figure 16 PJM five minute load and synchronized reserve on January 31, 2019, with PJM proposed ORDC price



PJM's ORDC prices would be nonzero throughout the early morning ramping period from 2:00 to 8:00 AM. The overall pattern of prices with PJM's proposed ORDC is not only not more intuitive than the current pricing method, it is less intuitive. Prices in Figure 16 are low with increasing load and high when load is falling for the first half of the day.

Scarcity Pricing

The PJM Real-Time Energy Market is based on a set of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).

PJM solves multiple RT SCED cases for each five minute target interval, beginning at approximately 10 to 14 minutes in advance of that interval. RT SCED cases are executed at instances that occur approximately every three minutes, with cases executed more frequently if necessary. Three SCED cases are executed at each instance, with different levels of load bias in each of the three scenarios.[14] On average, PJM operators approve more than one RT SCED case per five minute interval to send dispatch signals to resources. PJM operators select only a subset of these approved RT SCED cases to be used in LPC to calculate real-time LMPs. The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC. LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system.

The MMU analyzed the intervals where one or more solved RT SCED cases indicated a shortage of one or more reserve products. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement. The extended reserve requirement is defined as the reliability reserve requirement plus 190 MW.[15] Figure 17 shows, for January 30, January 31, and February 1, 2019, the number of intervals where at least one solved SCED case showed a shortage of reserves, the number of intervals where more than one solved SCED case showed a shortage of reserves, and the number of five minute intervals where the LPC solution showed a shortage of reserves which was reflected in energy prices.

PJM dispatchers select only a subset of approved RT SCED cases to be used in LPC to calculate real-time LMPs. It is unclear what criteria dispatchers use for selecting the specific RT SCED cases to be used in LPC for calculating prices for an interval. PJM should ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals.[16] This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC.

14 A case is executed when it begins to solve. Most but not all cases are solved. SCED cases take about one to two minutes to solve.

15 The reliability reserve requirement is equal to the output of the largest generator contingency in the reserve zone for synchronized reserves and 1.5 times the largest generator contingency in the reserve zone for primary reserves.

16 The Market Monitor introduced a problem statement to s stakeholder committee to evaluate the transparency in the dispatch and five minute pricing process. *See* "Five minute dispatch and pricing," Presented at the Market Implementation Committee (April 10, 2019), which can be accessed at <*https://www.pjm.com/-/media/committees-groups/committees/mic/20190410/20190410-item-07-rt-sced-problem-statement.ashx*>.

Figure 17 Number of five minute intervals with RT SCED shortage of reserves: January 30, 2019 through February 1, 2019

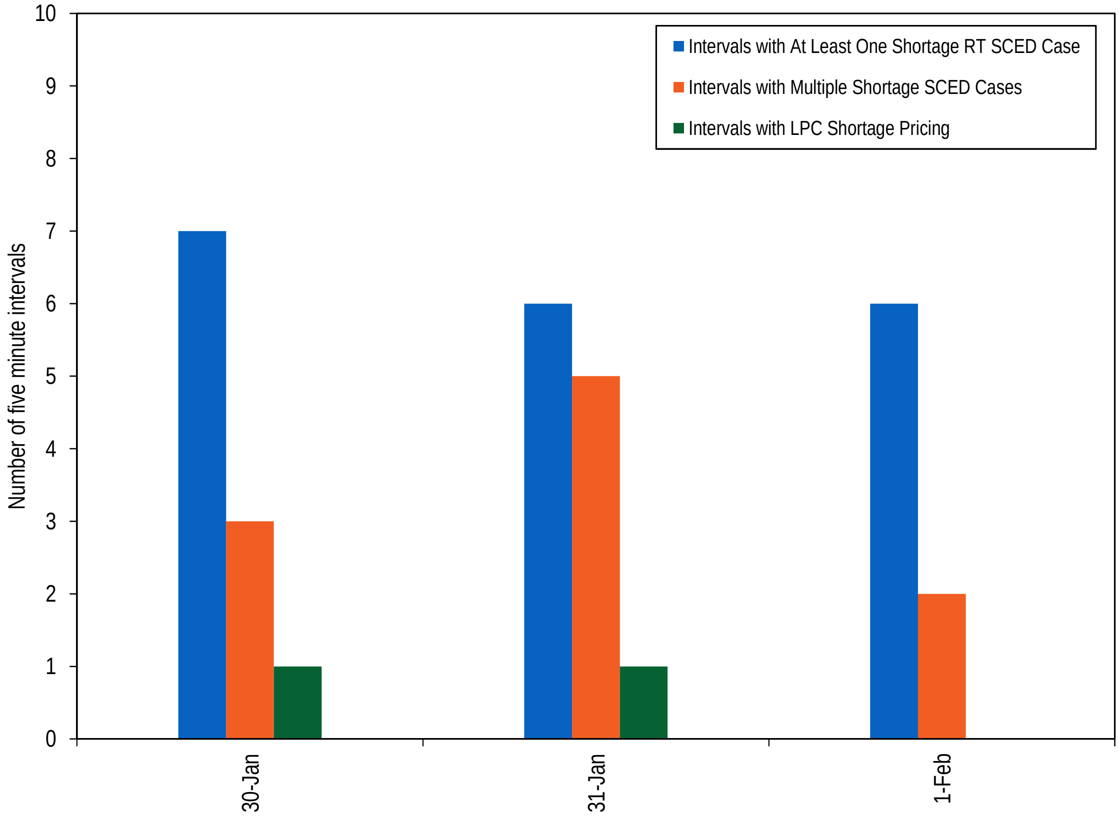
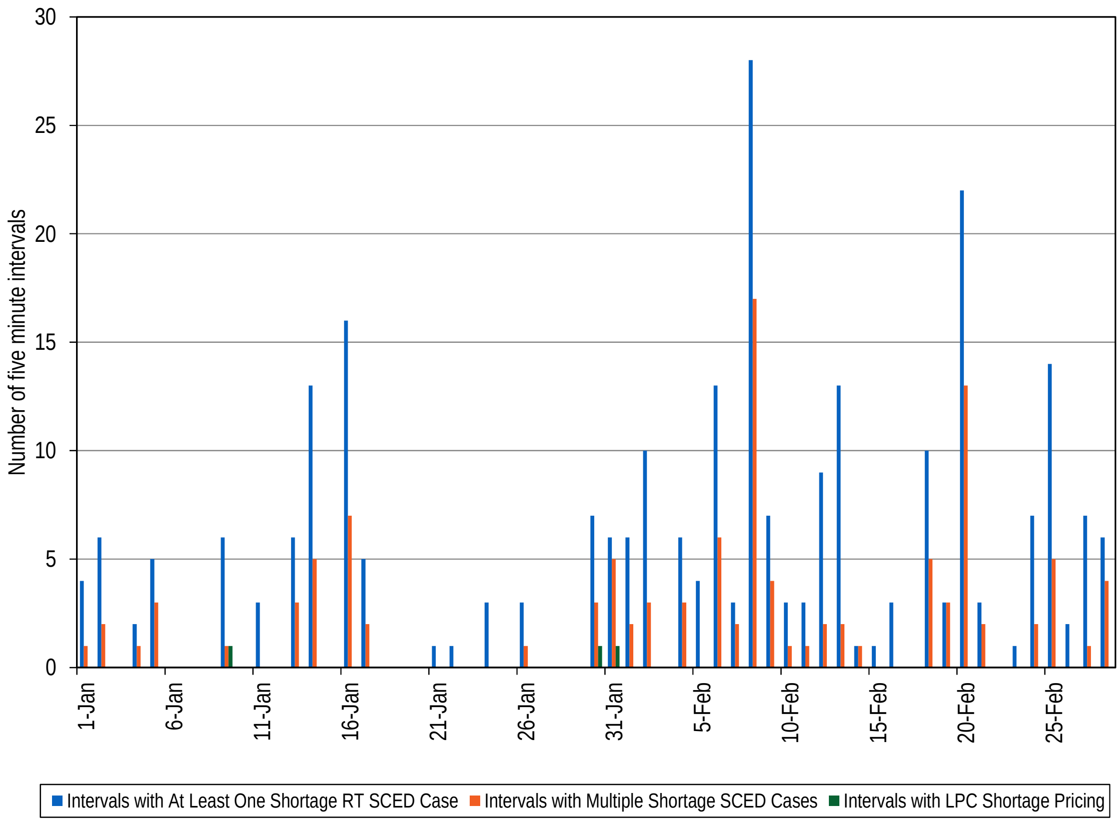


Figure 17 shows, for each day during the months of January and February, 2019, the number of intervals where at least one solved SCED case showed a shortage of reserves, the number of intervals where more than one solved SCED case showed a shortage of reserves, and the number of five minute intervals where the LPC solution showed a shortage of reserves.

Figure 18 Number of five minute intervals with RT SCED shortage of reserves: January 1, 2019 through February 28, 2019



The data show that PJM shortage pricing occurs less often than the market software solved cases indicate.

Assessment of Prices

Overall, winter peak LMPs for PJM reached levels consistent with the short run marginal cost of power on the system given market conditions with high load, ample supply, and higher than usual natural gas prices. Reserve pricing was consistent with system conditions, with supply and with the reserve requirement equal to the largest supply contingency. PJM had more than adequate reserves available, as shown in Figure 5.

For some five minute intervals when load rose quickly or generators tripped offline, scarcity conditions resulted. Shortage pricing occurred in some of those intervals. Correct specification of the reserve requirement in use by PJM operators, consistent approval of SCED cases indicating shortage, and consistent between SCED and LPC result would result in scarcity pricing in intervals where it may have been suppressed.

Uplift

Table 9 shows that total uplift credits in January 2019 were $7.9 million, significantly lower than total uplift in January in the previous four years. In January 2019, there were four days in which cold weather alerts were issued across the PJM footprint; January 21 through January 22, and January 30 through January 31. Table 10 shows the total uplift credits by credit type during the cold weather alerts in January 2019. Table 10 shows that uplift credits were highly concentrated on the cold weather alert days. The four days in January with cold weather alerts incurred $5.6 million in uplift credits or 70.5 percent of all uplift incurred in January. The majority of uplift credits were balancing operating reserve (BOR) credits which made up 79.2 percent of all uplift credits incurred during the four cold weather alert days in January 2019.

Table 9 Total uplift credits by credit type in the month of January: 2015 through 2019

Year	Day-Ahead	Balancing	LOC	Reactive	Other	Total
2015	$16,640,083	$19,215,609	$5,208,816	$1,827,905	$1,753,388	$44,645,800
2016	$7,375,244	$5,685,294	$1,711,494	$1,933	$8,098	$14,782,064
2017	$2,640,947	$7,035,869	$380,479	$1,253,263	$19,409	$11,329,967
2018	$4,777,752	$33,143,106	$21,728,594	$1,937,744	$42,807	$61,630,004
2019	$1,014,208	$5,353,061	$752,916	$82,337	$702,007	$7,904,530

Table 10 Total uplift credits by day and credit type during cold weather alerts days in January 2019

Date	Day-Ahead	Balancing	LOC	Reactive	Other	Total
1/21/19	$170,254	$820,123	$193,589	$70,355	$153,054	$1,407,375
1/22/19	$6,199	$1,789,976	$133,921	$0	$67,619	$1,997,715
1/30/19	$17,310	$603,246	$262,621	$11,983	$0	$895,160
1/31/19	$1,845	$1,200,324	$73,535	$0	$0	$1,275,704
Total	$195,608	$4,413,670	$663,666	$82,337	$220,673	$5,575,954
Share of Total	3.5%	79.2%	11.9%	1.5%	4.0%	100.0%

Table 11 shows that combustion turbines (CTs) received 74.1 percent of all uplift credits during the cold weather alert days. This was the result of CTs being committed in the Real-Time Energy Market. Table 12 shows that 50.8 percent of real-time generation by CTs operated outside a day-ahead schedule.[17] CTs operating outside of a day-ahead scheduled received $3.6 million or 65.6 percent of all uplift credits during the cold weather alert days in January.

17 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

Table 12 shows that 67.1 percent of the generation (MWh) from CTs operating outside a day-ahead schedule were uneconomic; operated on real-time offers that were greater than day-ahead offers; were block loaded; or did not follow dispatch. The uplift payments do not include all revenues and costs for the entire day causing uplift to be higher than necessary. Combined cycle (CC) units received the second largest share of BOR credits with $0.69 million in credits. The majority of credits to CC units, $0.44 million or 63.4 percent, were for units committed in real-time to cover for transmission problems, not committed to provide reserves.

Table 11 Total uplift credits by credit and unit type during cold weather alert days in January 2019

Unit Type	Day-Ahead	Balancing	LOC	Reactive	Local Constraint	Total	Share of Total
Combined Cycle	$52,141	$686,112	$232,453	$0	$220,673	$1,191,379	21.4%
Combustion Turbine	$284	$3,659,832	$395,451	$76,578	$0	$4,132,144	74.1%
Diesel	$2,685	$28,398	$23,269	$5,759	$0	$60,111	1.1%
Steam-Coal	$140,498	$22,704	$8,669	$0	$0	$171,871	3.1%
Steam-Others	$0	$16,578	$3,825	$0	$0	$20,403	0.4%
Wind	$0	$46	$0	$0	$0	$46	0.0%
Total	$195,608	$4,413,624	$663,666	$82,337	$220,719	$5,575,954	100.0%

Table 12 Generation and balancing operating reserve credits for combustion turbines during cold weather alert days in January 2019

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Date	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
1/21/19	24.0	41.6%	13.3%	$0.0	33.8	58.4%	55.8%	$0.8
1/22/19	12.4	39.1%	25.2%	$0.0	19.4	60.9%	83.8%	$1.3
1/30/19	13.9	49.2%	11.8%	$0.0	14.3	50.8%	72.0%	$0.6
1/31/19	24.9	70.9%	65.5%	$0.0	10.2	29.1%	92.5%	$1.0
Total	75.3	49.2%	32.4%	$0.0	77.8	50.8%	67.1%	$3.6

The IMM has made several recommendations to improve the calculation of uplift credits that would have resulted in even lower and more appropriate uplift payments. The recommendations include the elimination of day-ahead operating reserve credits, the calculation of balancing operating reserves (BOR) and lost opportunity cost (LOC) credits on a daily 24-hour basis, and the payment of uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. Table 13 shows that if the recommendation to eliminate day-ahead operating reserves were implemented, day-ahead operating reserve credits would have been reduced by 98.7 percent. If BOR credits and LOC credits were calculated on a daily basis they would have been reduced by 13.1 and 16.3 percent.

The largest reduction comes from calculating BOR credits based on the lower of real-time output or the dispatch signal. This would have resulted in a $1.08 million or 23.1 percent decrease in BOR credits during the cold weather alert days. The IMM has identified that there are a large number of resources that do not follow the dispatch signal and operate at levels higher than justified by LMP. These resources are being made whole for their entire output even if it was not requested by PJM. Making units whole to the lower of their output or dispatch signal ensures that only the output level requested by PJM is eligible to receive uplift credits. The combined impact of all of the proposals would have reduced uplift by $1.87 million or 35.5 percent of day-ahead, BOR, and LOC credits incurred during the cold weather alert days in January 2019.

Table 13 Impact of proposed recommendations to calculation of uplift credits on credits during cold weather alert days in 2019

Proposal	Credits Impacted	Current Credits (millions)	Proposal Credits (millions)	Difference (millions)	Percent Difference
Eliminate day-ahead operating reserve credits	Day-ahead generator	$0.196	$0.001	($0.195)	(99.7%)
Calculate the need for balancing operating reserve credits on a daily basis	Balancing operating reserve	$4.41	$3.83	($0.59)	(13.3%)
Calculate lost opportunity cost credits on a daily basis	Lost Opportunity Cost Credits	$0.66	$0.56	($0.11)	(16.3%)
Calculate the need for balancing credits on the lower of real-time output or the dispatch signal	Balancing operating reserve	$4.41	$3.38	($1.03)	(23.4%)
Total of all recommendations combined	Day-ahead generator Balancing operating reserve Lost opportunity cost	$5.27	$3.40	($1.87)	(35.5%)

Price Formation

PJM energy and reserve prices and uplift in January 2019 did not reveal any market design flaws that would justify the Commission finding the energy and reserve markets to be unjust and unreasonable. Energy prices and uplift increased with the short run marginal costs of gas fired generators. Low reserve prices corresponded to the supply and demand fundamentals. To the extent that lack of clear rules about the consistency between SCED and LPC intervals resulted in suppressing scarcity prices, that issue can be addressed directly. Overall, PJM's markets performed efficiently and as designed in January 2019.

ATTACHMENT B

ORDC Simulation Results: Version 2

The Independent Market Monitor for PJM

May 10, 2019

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Introduction

PJM's March 29th Price Formation Filing includes simulation results estimating the impact of PJM's proposal. The Market Monitor replicated PJM's simulations using identical software and the same input data as PJM. Replication allows the Market Monitor to verify the results, understand the modelling assumptions, analyze the results in greater detail, and perform alternative simulation scenarios.

The Market Monitor also performed simulations using alternative specifications of the Operating Reserve Demand Curve (ORDC) to demonstrate how market results may change under different proposals.

PJM used PowerGEM's PROBE Perfect Dispatch Model (PROBE Ver 2.85_1-M) to run its simulations. PROBE Ver 2.85_1-M contained an error that caused the synchronized reserve shadow price (used to determine the price of synchronized reserves) to be greater than the prices indicated by the ORDC curves. The result of the error is that the simulation results overstate the prices and the overall costs of reserves. This issue was identified and corrected in PROBE Ver 2.85_1-P and later versions. The Market Monitor used PROBE Ver 2.85 1-R, which incorporated the fix, to produce its own simulation results. PROBE Ver 2.85_1-R produces synchronized reserve shadow prices that are consistent with the ORDC curves.

The PowerGEM PROBE Perfect Dispatch software is designed to optimize resource commitment and dispatch to the find the lowest production cost solution for energy and reserve requirements, subject to resource and network constraints in a given 24 hours period. One of the inputs to this optimization is the set of resources types that can have their commitment and dispatch changed relative to an initial assumed start state. In the typical perfect dispatch case only diesel and combustion turbine resources can have commitment changes, while other resource types are limited to redispatch, unless otherwise specified. The larger the set of resource types than can have their commitment and dispatch optimized, the more optimal the solution in terms of minimizing production cost given energy and reserve requirements. The PROBE software will change the commitment and dispatch of a given resource set to minimize the cost of any significant changes in market conditions within the 24 hour period. This same flexibility in system dispatch and commitment is generally not available in actual operations. This means that the simulations will tend to have fewer periods of high prices and that the high prices will tend to be lower than in an actual real-time market day with the same load conditions. The simulated market results will underestimate the real world costs of meeting the energy and reserve requirements in the simulation cases.

PJM Simulations

PJM performed three simulations: Cases A, B, and C.

Case A includes no changes in the dispatch and pricing process from PJM's standard Perfect Dispatch simulation software.[1] PJM currently uses the Perfect Dispatch software to benchmark its actual real-time market performance against a simulated outcome that economically optimizes resource dispatch and fast start resource commitment.[2] Case A represents this optimal dispatch and commitment and does not represent the actual status quo. Thus, comparisons using Case A as the benchmark will underestimate the real world costs of meeting the energy and reserve requirements in the simulation cases. PJM also modifies the Case A results by incorporating the payment of a single clearing price to all synchronized reserves.

Case B uses a change in the Perfect Dispatch software settings to extend the economic evaluation of resource commitments to steam units, typically committed prior to the operating day by the Day-Ahead Energy Market, the Day-Ahead Reliability Assessment, or manually by reliability processes. Case B presents a significant departure from reality by allowing the software to decommit resources required by PJM for reliability. Day-ahead reliability commitments accounted for an average of 1,100 MW of generation per hour in 2018.

Case C introduces PJM's proposed ORDC to Case B. PJM argues that the relevant comparison to assess the impact of the ORDC proposal is the comparison of Case B to Case C. Because Case B modifies actual PJM operating conditions, it is not an accurate base case. The Market Monitor also compares Case A to Case C and creates a Case A ORDC that implements the ORDC in the Case A model. If it is the case, and PJM implies that it is, that the ORDC would replace manual operator commitments with market commitments, the relevant comparison is Case A to Case C, because Case A contains the steam unit commitments made by operators.[3] Case B removes all uneconomic operator commitments.

The Market Monitor disagrees with PJM's conclusion that a 30 minute time horizon is appropriate for the 10 minute reserve products. Case C 15 minute presents a case where the ORDC is shifted inward using a 15 minute forecast time horizon for the synchronized and primary reserve demand curves.

Table 1 shows the summary results for the five simulation cases.

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1 The Perfect Dispatch software is PowerGEM's PROBE Perfect Dispatch Model.

2 *See* PJM Perfect Dispatch Fact Sheet, <https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/perfect-dispatch-fact-sheet.ashx?la=en>, last accessed April 19, 2019.

3 *See* March 29th Filing, Pilong Testimony.

Table 1 Comparison of simulation cases

	Case A	Case B	Case C	Case A ORDC	Case C 15
Load Weighted LMP ($/MWh)	$35.80	$37.30	$37.76	$36.91	$37.61
Generator Weighted LMP ($/MWh)	$33.29	$34.72	$35.18	$34.39	$35.03
Generator Energy Revenue ($ millions)	$26,796.6	$27,943.2	$28,312.6	$27,679.3	$28,191.9
Weighted Synchronized Reserve MCP ($/MWh)	$1.99	$2.58	$6.33	$6.05	$4.66
Weighted Non-Synchronized Reserve MCP ($/MWh)	$1.03	$1.25	$3.21	$3.08	$2.34
Weighted Secondary Reserve MCP ($/MWh)	NA	NA	$0.0004	$0.0004	$0.0015
Hourly Average Cleared Synchronized Reserve (MW/hour)	1,817.8	1,818.2	3,167.3	3,189.6	2,866.6
Hourly Average Cleared Non-Synchronized Reserve (MW/hour)	634.6	634.2	677.6	678.1	677.3
Hourly Average Cleared Secondary Reserve (MW/hour)	NA	NA	1,944.0	1,928.2	2,195.2
Hourly Average Cleared Total Reserve (MW/hour)	2,452.4	2,452.4	5,789.0	5,795.9	5,739.0
Total Cleared Synchronized Reserve (millions MWh)	15.5	15.5	27.0	27.2	24.4
Total Cleared Non-Synchronized Reserve (millions MWh)	5.4	5.4	5.8	5.8	5.8
Total Cleared Secondary Reserve (millions MWh)	NA	NA	16.6	16.4	18.7
Reserve Revenue ($ millions)	$36.4	$46.7	$189.3	$182.1	$127.3
Uplift ($ millions)	$109.9	$30.4	$27.5	$93.0	$28.0
Bid Production Cost ($ millions)	$13,229.6	$13,121.2	$13,152.0	$13,256.8	$13,135.8
Total Energy and Reserve Market Revenues ($ millions)	$26,833.0	$27,989.9	$28,501.9	$27,861.5	$28,319.2

The Market Monitor provides the detailed hourly and daily simulation results on its website.

Case B to Case C

PJM argues that the relevant comparison to assess the impact of the ORDC proposal is the comparison of Case B to Case C. Because Case B modifies actual PJM operating conditions, it is not an accurate base case. The comparison of Case B to Case C understates the impact of PJM's proposed changes on the actual market outcomes. The Market Monitor includes this comparison in order to highlight some of the detailed impacts of the comparison that PJM did not include in their filing. PJM presents the changes from Case B to Case C for the calendar year 2018 as the impact of implementing its proposed ORDC. In addition to the summary metrics provide in PJM's filing, the Market Monitor provides additional detailed metrics for each case.

Table 2 provides monthly load weighted average energy prices. The increase in LMP due to the ORDC is much greater in January, primarily resulting from higher base prices during the first week of January.

Table 2 PJM load-weighted average LMP: 2018, Case B to Case C

	Load Weighted LMP ($/MWh)		
	Case B	Case C	Difference
Jan	$73.87	$75.01	$1.14
Feb	$27.58	$28.00	$0.42
Mar	$30.64	$30.97	$0.34
Apr	$34.10	$34.73	$0.63
May	$31.96	$32.33	$0.37
Jun	$30.13	$30.48	$0.35
Jul	$34.53	$34.85	$0.31
Aug	$36.02	$36.22	$0.20
Sep	$35.59	$35.72	$0.13
Oct	$33.90	$34.52	$0.63
Nov	$37.45	$38.05	$0.60
Dec	$33.23	$33.66	$0.43
Total	$37.30	$37.76	$0.46

The LMP increases vary geographically. Table 3 shows the differences in annual average hub LMPs and Table 4 shows zonal load-weighted average LMP increases.

Table 3 Average hub LMP: 2018, Case B to Case C

	Average LMP ($/Mwh)		
	Case B	Case C	Difference
AEP GEN HUB	$32.20	$32.68	$0.48
AEP-DAYTON HUB	$33.52	$34.02	$0.49
ATSI GEN HUB	$34.40	$34.87	$0.47
CHICAGO GEN HUB	$28.68	$29.07	$0.39
CHICAGO HUB	$29.29	$29.68	$0.38
DOMINION HUB	$37.25	$37.73	$0.48
EASTERN HUB	$37.34	$37.64	$0.30
N ILLINOIS HUB	$29.09	$29.47	$0.38
NEW JERSEY HUB	$35.14	$35.55	$0.40
OHIO HUB	$33.28	$33.78	$0.50
WEST INT HUB	$35.30	$35.75	$0.46
WESTERN HUB	$35.51	$36.01	$0.50

Table 4 PJM load-weighted average LMP by zone: 2018, Case B to Case C

	Load Weighted LMP ($/Mwh)		
	Case B	Case C	Difference
AECO	$37.81	$38.30	$0.49
AEP	$36.65	$37.17	$0.51
AP	$38.12	$38.62	$0.50
ATSI	$37.24	$37.71	$0.48
BGE	$42.13	$42.63	$0.50
COMED	$30.74	$31.15	$0.41
CPP	$35.67	$36.21	$0.55
DAY	$36.44	$36.97	$0.53
DEOK	$36.12	$36.61	$0.49
DOM	$41.06	$41.56	$0.50
DPL	$41.46	$41.72	$0.26
DUQ	$36.95	$37.42	$0.47
EKPC	$35.75	$36.28	$0.53
JCPL	$37.81	$38.22	$0.41
METED	$38.14	$38.55	$0.42
PECO	$37.55	$37.98	$0.43
PENELEC	$36.94	$37.46	$0.52
PEPCO	$40.86	$41.35	$0.50
PPL	$37.40	$37.77	$0.38
PSEG	$37.34	$37.72	$0.38

Average generator weighted average LMP increases differ from load-weighted average LMP increases. Table 5 shows the generation-weighted average LMP at generation pricing nodes by zone. Typically, load LMP exceeds generator LMP due to congestion and losses, which is the case for most zones in both Cases B and C. However, generator LMPs increase more than load LMPs from Case B to Case C for nine of 19 zones.

Table 5 PJM generation-weighted average LMP by zone: 2018, Case B to Case C

	Generation Weighted LMP ($/MWh)		
	Case B	Case C	Difference
AECO	$37.18	$37.55	$0.38
AEP	$33.41	$33.91	$0.50
AP	$35.26	$35.75	$0.49
ATSI	$35.95	$36.45	$0.49
BGE	$41.81	$42.30	$0.49
COMED	$28.99	$29.36	$0.37
DAY	$38.76	$39.46	$0.70
DEOK	$33.44	$33.94	$0.50
DOM	$40.34	$40.85	$0.50
DPL	$44.92	$45.12	$0.20
DUQ	$35.68	$36.14	$0.45
EKPC	$36.29	$36.87	$0.58
JCPL	$33.85	$34.24	$0.39
METED	$34.06	$34.45	$0.39
OVEC	$31.31	$31.80	$0.49
PECO	$34.78	$35.18	$0.40
PENELEC	$34.75	$35.37	$0.62
PEPCO	$43.84	$44.50	$0.66
PPL	$35.42	$35.81	$0.39
PSEG	$34.80	$35.21	$0.42

Table 6 shows the increases in monthly MW weighted average reserve clearing prices for synchronized and primary reserves. Average prices for secondary reserves are zero. Reserve prices more than double annually, increasing in all months and by the largest amounts in the winter months.

Table 6 Monthly PJM reserve market prices: 2018, Case B to Case C

	Reserve Weighted Average Market Clearing Prices ($/MW)					
	Case B		Case C		Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	$6.03	$1.43	$15.80	$6.66	$9.77	$5.23
Feb	$2.36	$0.31	$6.65	$2.57	$4.30	$2.26
Mar	$3.85	$1.94	$6.71	$3.04	$2.85	$1.10
Apr	$4.96	$2.47	$7.90	$3.87	$2.94	$1.40
May	$3.20	$1.09	$5.82	$2.82	$2.62	$1.72
Jun	$1.29	$1.06	$3.74	$2.30	$2.45	$1.24
Jul	$1.45	$1.08	$4.11	$2.25	$2.65	$1.17
Aug	$0.81	$0.45	$3.59	$1.89	$2.78	$1.44
Sep	$1.74	$1.47	$4.23	$2.82	$2.49	$1.35
Oct	$2.38	$1.94	$6.04	$3.83	$3.66	$1.89
Nov	$1.93	$1.29	$5.92	$3.13	$3.99	$1.84
Dec	$0.95	$0.59	$5.46	$2.89	$4.50	$2.30
Annual	$2.58	$1.25	$6.33	$3.21	$3.75	$1.95

Table 7 shows the monthly increases in the quantity of reserves. The increase in synchronized reserves ranges from 51.0 percent in April to 92.9 percent in February. The increases in primary reserves range from 0.7 percent in October to 19.5 percent in February.

Table 7 Monthly PJM reserve market clearing: 2018, Case B to Case C

	Cleared Reserve MWh							
	Case B		Case C		Difference		Percent Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	1,333,092.8	460,168.2	2,418,397.5	546,578.3	1,085,304.7	86,410.1	81.4%	18.8%
Feb	1,104,579.4	424,887.5	2,130,543.1	507,781.1	1,025,963.7	82,893.6	92.9%	19.5%
Mar	1,320,246.7	480,453.2	2,040,335.0	508,224.3	720,088.4	27,771.1	54.5%	5.8%
Apr	1,242,142.7	444,263.6	1,875,125.5	478,559.4	632,982.8	34,295.9	51.0%	7.7%
May	1,224,596.4	450,672.8	1,926,473.6	487,224.9	701,877.2	36,552.1	57.3%	8.1%
Jun	1,260,166.9	415,391.3	2,259,288.5	423,859.6	999,121.6	8,468.4	79.3%	2.0%
Jul	1,311,952.1	484,208.9	2,367,598.0	507,157.2	1,055,645.9	22,948.3	80.5%	4.7%
Aug	1,298,609.1	481,900.0	2,377,283.8	512,919.8	1,078,674.7	31,019.7	83.1%	6.4%
Sep	1,307,381.3	372,220.2	2,329,466.3	378,763.9	1,022,085.0	6,543.7	78.2%	1.8%
Oct	1,462,476.9	435,479.7	2,450,038.5	438,649.3	987,561.6	3,169.7	67.5%	0.7%
Nov	1,310,593.5	471,232.5	2,278,685.6	489,567.6	968,092.0	18,335.2	73.9%	3.9%
Dec	1,315,281.3	482,772.0	2,532,455.1	494,226.7	1,217,173.9	11,454.7	92.5%	2.4%
Total	15,491,118.8	5,403,649.7	26,985,690.1	5,773,512.0	11,494,571.3	369,862.3	74.2%	6.8%

Increases in energy prices, reserve prices, and reserve clearing MW create higher revenues for suppliers. Table 8 provides the monthly generator revenue comparison for Case B to Case C. The total generator revenue increase from Case B to Case C is $511.9 million. Energy revenues increase by $369.4 million, accounting for 72.1 percent of the increase. Synchronized reserve revenues increase by $130.8 million, accounting for 25.6 percent of increased revenues.

Table 8 Monthly PJM generator revenue: 2018, Case B to Case C

	Revenue ($)											
	Case B				Case C				Difference			
	Generation	SR	PR	OR	Generation	SR	PR	OR	Generation	SR	PR	OR
Jan	$5,081,623,092.5	$8,041,039.6	$657,447.2	$0.0	$5,179,435,042.5	$38,219,472.1	$3,640,986.1	$6,807.5	$97,811,950.0	$30,178,432.6	$2,983,538.9	$6,807.5
Feb	$1,519,472,468.7	$2,603,153.7	$132,698.2	$0.0	$1,543,724,380.7	$14,175,045.2	$1,307,337.2	$0.0	$24,251,912.0	$11,571,891.5	$1,174,639.1	$0.0
Mar	$1,859,115,556.6	$5,089,052.2	$933,042.7	$0.0	$1,880,105,031.9	$13,687,271.3	$1,546,359.5	$0.0	$20,989,475.3	$8,598,219.1	$613,316.8	$0.0
Apr	$1,826,358,822.0	$6,159,167.4	$1,098,624.4	$0.0	$1,859,479,992.5	$14,809,220.0	$1,853,779.5	$0.0	$33,121,170.5	$8,650,052.6	$755,155.2	$0.0
May	$1,775,298,936.7	$3,915,318.4	$492,517.1	$0.0	$1,796,050,045.9	$11,202,492.5	$1,372,517.0	$0.0	$20,751,109.2	$7,287,174.1	$879,999.9	$0.0
Jun	$1,935,187,664.6	$1,628,149.4	$439,857.2	$0.0	$1,958,510,650.6	$8,451,910.9	$976,354.2	$0.0	$23,322,986.0	$6,823,761.5	$536,496.9	$0.0
Jul	$2,580,228,898.0	$1,907,918.9	$521,565.1	$0.0	$2,604,621,249.7	$9,728,911.1	$1,140,853.8	$0.0	$24,392,351.7	$7,820,992.2	$619,288.7	$0.0
Aug	$2,750,194,638.6	$1,050,710.0	$214,835.1	$0.0	$2,768,400,772.2	$8,531,431.0	$967,552.5	$0.0	$18,206,133.6	$7,480,720.9	$752,717.3	$0.0
Sep	$2,222,742,250.0	$2,271,640.2	$546,674.0	$0.0	$2,234,089,436.4	$9,855,606.3	$1,067,524.7	$0.0	$11,347,186.4	$7,583,966.2	$520,850.7	$0.0
Oct	$2,024,751,056.9	$3,481,601.1	$845,140.1	$0.0	$2,062,113,922.3	$14,807,457.1	$1,680,044.1	$0.0	$37,362,865.4	$11,325,855.9	$834,904.0	$0.0
Nov	$2,273,655,880.6	$2,530,961.9	$608,868.5	$0.0	$2,305,248,950.4	$13,485,785.4	$1,531,255.5	$0.0	$31,593,069.8	$10,954,823.6	$922,387.0	$0.0
Dec	$2,094,561,286.0	$1,254,060.2	$283,817.4	$0.0	$2,120,810,211.0	$13,815,461.4	$1,427,978.3	$0.0	$26,248,925.0	$12,561,401.2	$1,144,160.8	$0.0
Total	$27,943,190,551.2	$39,932,773.1	$6,775,087.1	$0.0	$28,312,589,686.1	$170,770,064.5	$18,512,542.5	$6,807.5	$369,399,134.9	$130,837,291.4	$11,737,455.4	$6,807.5

Table 9 shows generator revenues by technology type. Table 10 shows generator revenues per installed capacity (ICAP) MW by technology type. Consistent with their, roughly equal, high shares of energy output in PJM, steam, nuclear, and combined cycle gas units receive the greatest benefits from the ORDC.[4]

Revenues increase most for coal steam units. This result is expected. Coal steam units have high capacity factors due to their moderate marginal costs and inflexibility in starting and shutting down, so steam units receive a large share of the benefit of higher energy prices. Coal units' energy revenues increase by $120.4 million, reserve revenues increase by $23.2 million and total revenues increase by $143.6 million.

Nuclear units also have high capacity factors due to their low marginal cost and inflexibility. Nuclear units' energy revenues increase by $110.1 million but nuclear units do not provide reserves.

Combined cycle units have high capacity factors, but not as high as nuclear and steam units. Combined cycle units' energy revenues increase by $75.0 million, reserve revenues increase by $72.6 million, and total revenues increase by $147.6 million. Combined cycle units greater flexibility leads to the largest increase in reserve revenues by technology type.

[4] *See* Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, Vol. 2, Section 3: Energy Market, Table 3-9.

Table 9 Generator revenues by technology type: 2018, Case B to Case C

	Revenue ($)								
	Case B			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$148,766.5	$0.9	$0.0	$151,937.2	$533.1	$55.4	$3,170.7	$532.2	$55.4
CC	$7,759,725,631.2	$22,947,672.0	$563.7	$7,834,745,587.7	$95,559,023.1	$4,333.1	$75,019,956.5	$72,611,351.1	$3,769.4
CT Natural Gas	$888,699,914.9	$5,773,510.7	$2,003,092.8	$926,170,750.9	$26,927,506.5	$6,407,041.0	$37,470,836.0	$21,153,995.8	$4,403,948.2
CT Oil	$46,324,308.3	$1,690,138.3	$4,474,516.6	$46,963,248.8	$5,005,884.6	$11,325,661.7	$638,940.5	$3,315,746.3	$6,851,145.1
CT Other	$5,899,724.1	$11,965.6	$23,344.2	$5,975,629.3	$41,186.5	$60,698.1	$75,905.2	$29,220.9	$37,353.9
Fuel Cell	$7,469,775.2	$0.0	$0.0	$7,556,319.5	$0.0	$0.0	$86,544.3	$0.0	$0.0
Hydro	$484,669,838.3	$2,887,448.2	$104,804.6	$489,809,456.5	$9,556,905.8	$265,559.0	$5,139,618.2	$6,669,457.6	$160,754.4
Nuclear	$9,049,991,523.7	$0.0	$0.0	$9,160,068,376.6	$0.0	$0.0	$110,076,852.9	$0.0	$0.0
RICE Natural Gas	$14,189,947.6	$96,194.4	$0.0	$14,478,100.4	$461,374.5	$0.0	$288,152.7	$365,180.1	$0.0
RICE Oil	$1,457,402.1	$2,056.5	$104,177.5	$1,401,120.9	$7,445.1	$264,985.1	($56,281.2)	$5,388.6	$160,807.6
RICE Other	$53,295,887.4	$505,299.9	$57,816.4	$53,795,291.6	$1,397,551.4	$141,371.5	$499,404.1	$892,251.5	$83,555.1
Solar	$66,827,029.5	$0.0	$0.0	$67,156,170.0	$0.0	$0.0	$329,140.5	$0.0	$0.0
Steam Coal	$8,410,313,995.3	$5,163,185.9	$6,771.2	$8,530,672,556.5	$28,365,453.2	$42,837.5	$120,358,561.3	$23,202,267.4	$36,066.3
Steam Natural Gas	$271,573,014.0	$587,459.2	$0.0	$278,003,548.3	$2,641,350.2	$0.0	$6,430,534.3	$2,053,890.9	$0.0
Steam Oil	$40,052,929.0	$40,336.8	$0.0	$40,905,504.0	$187,324.2	$0.0	$852,575.1	$146,987.5	$0.0
Steam Other	$230,868,650.2	$226,751.1	$0.0	$233,449,453.0	$616,857.5	$0.0	$2,580,802.8	$390,106.4	$0.0
Wind	$611,688,031.0	$0.0	$0.0	$621,289,059.6	$0.0	$0.0	$9,601,028.6	$0.0	$0.0
Total	$27,943,196,368.3	$39,932,019.4	$6,775,087.1	$28,312,592,110.7	$170,768,395.8	$18,512,542.5	$369,395,742.4	$130,836,376.4	$11,737,455.4

Table 10 Generator revenues per ICAP MW by technology: 2018, Case B to Case C

	Revenue ($/MW)								
	Case B			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$3,719.16	$0.02	$0.00	$3,798.43	$13.33	$1.38	$79.27	$13.31	$1.38
CC	$161,695.31	$478.18	$0.01	$163,258.56	$1,991.24	$0.09	$1,563.25	$1,513.06	$0.08
CT Natural Gas	$35,493.90	$230.59	$80.00	$36,990.46	$1,075.46	$255.89	$1,496.55	$844.87	$175.89
CT Oil	$11,688.61	$426.46	$1,129.02	$11,849.83	$1,263.09	$2,857.71	$161.22	$836.63	$1,728.69
CT Other	$132,876.67	$269.50	$525.77	$134,586.24	$927.62	$1,367.07	$1,709.58	$658.13	$841.30
Fuel Cell	$248,992.51	$0.00	$0.00	$251,877.32	$0.00	$0.00	$2,884.81	$0.00	$0.00
Hydro	$60,032.93	$357.65	$12.98	$60,669.54	$1,183.75	$32.89	$636.61	$826.10	$19.91
Nuclear	$259,519.54	$0.00	$0.00	$262,676.13	$0.00	$0.00	$3,156.59	$0.00	$0.00
RICE Natural Gas	$117,856.71	$798.96	$0.00	$120,250.00	$3,832.01	$0.00	$2,393.30	$3,033.06	$0.00
RICE Oil	$6,344.81	$8.95	$453.54	$6,099.79	$32.41	$1,153.61	($245.02)	$23.46	$700.08
RICE Other	$147,642.22	$1,399.80	$160.17	$149,025.68	$3,871.55	$391.63	$1,383.47	$2,471.75	$231.47
Solar	$48,151.96	$0.00	$0.00	$48,389.13	$0.00	$0.00	$237.16	$0.00	$0.00
Steam Coal	$130,644.23	$80.20	$0.11	$132,513.86	$440.62	$0.67	$1,869.63	$360.42	$0.56
Steam Natural Gas	$27,083.90	$58.59	$0.00	$27,725.22	$263.42	$0.00	$641.32	$204.83	$0.00
Steam Oil	$17,459.86	$17.58	$0.00	$17,831.52	$81.66	$0.00	$371.65	$64.07	$0.00
Steam Other	$194,252.12	$190.79	$0.00	$196,423.60	$519.02	$0.00	$2,171.48	$328.23	$0.00
Wind	$67,824.41	$0.00	$0.00	$68,888.98	$0.00	$0.00	$1,064.57	$0.00	$0.00
Total	$133,665.02	$191.01	$32.41	$135,432.01	$816.86	$88.55	$1,766.99	$625.85	$56.15

To estimate the increase in carbon dioxide emissions due to the ORDC, the emissions rate for each technology, as calculated by the EIA, is multiplied by a generic heat rate for the technology and the simulated MWh of energy.[5] Table 11 provides the estimated increase in CO_2 emissions in short tons.

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5 Carbon Dioxide Emissions Coefficients, Energy Information Administration, <https://www.eia.gov/environment/emissions/co2_vol_mass.php>, accessed May 9, 2019.

Table 11 Estimated emissions increase: 2018, Case B to Case C

	CO2 Rate (lbs/MMBtu)	Heat Rate (MMBtu/MWh)	CO2 Rate (tons/MWh)	CO2 Case B (tons)	CO2 Case C (tons)	CO2 Difference (tons)
Battery						
CC	117.00	7.5	0.44	99,811,925	99,450,170	(361,755)
CT Natural Gas	117.00	11.0	0.64	11,023,488	11,471,605	448,117
CT Oil	161.30	13.0	1.05	246,259	246,871	613
CT Other	117.00	11.0	0.64	106,222	106,192	(30)
Fuel Cell						
Hydro						
Nuclear						
RICE Natural Gas	117.00	11.0	0.64	205,511	209,061	3,550
RICE Oil	161.30	13.0	1.05	9,586	9,543	(43)
RICE Other	117.00	11.0	0.64	947,615	947,067	(548)
Solar						
Steam Coal	210.20	11.0	1.16	271,043,498	271,055,453	11,955
Steam Natural Gas	117.00	11.0	0.64	3,309,329	3,366,226	56,897
Steam Oil	161.30	11.0	0.89	287,795	288,764	969
Steam Other	117.00	11.0	0.64	4,074,738	4,074,302	(436)
Wind						
Total				386,991,227	387,150,952	159,725

Case A to Case C

The comparison of Case A to Case C provides a better estimate of the results of PJM's proposed ORDC compared to the status quo, although the status quo is adjusted to incorporate optimal resource dispatch and fast start resource commitment. A comparison of Case A to Case C shows a higher increase in energy prices, because Case A has lower prices than Case B. Case A prices are lower because more generation is online in Case A, reflecting actual market operations. Case C and Case B allow the software to decommit uneconomic steam units, which are online for reliability or constraints at PJM's instruction.

If it is the case, and PJM implies that it is, that the ORDC would replace manual operator commitments with market commitments, the relevant comparison is Case A to Case C, because Case A contains the steam unit commitments made by operators. Case B removes all uneconomic operator commitments.

Table 12 provides monthly load weighted average energy prices. The increases in LMP due to the ORDC are higher when comparing Case A to Case C, rather than Case B to Case C.

Table 12 PJM load-weighted average LMP: 2018, Case A to Case C

	Load Weighted LMP ($/Mwh)		
	Case A	Case C	Difference
Jan	$68.39	$75.01	$6.62
Feb	$25.67	$28.00	$2.33
Mar	$28.82	$30.97	$2.16
Apr	$33.19	$34.73	$1.54
May	$30.80	$32.33	$1.53
Jun	$28.75	$30.48	$1.72
Jul	$33.64	$34.85	$1.21
Aug	$35.42	$36.22	$0.80
Sep	$34.73	$35.72	$0.99
Oct	$32.92	$34.52	$1.60
Nov	$36.87	$38.05	$1.18
Dec	$32.37	$33.66	$1.29
Total	$35.80	$37.76	$1.96

Table 13 shows the differences in annual average PJM trading hub LMPs.

Table 13 Average hub LMP: 2018, Case A to Case C

	Average LMP ($/MWh)		
	Case A	Case C	Difference
AEP GEN HUB	$31.08	$32.68	$1.60
AEP-DAYTON HUB	$32.43	$34.02	$1.59
ATSI GEN HUB	$33.18	$34.87	$1.69
CHICAGO GEN HUB	$27.39	$29.07	$1.67
CHICAGO HUB	$27.97	$29.68	$1.71
DOMINION HUB	$35.66	$37.73	$2.07
EASTERN HUB	$35.78	$37.64	$1.86
N ILLINOIS HUB	$27.77	$29.47	$1.70
NEW JERSEY HUB	$33.69	$35.55	$1.86
OHIO HUB	$32.21	$33.78	$1.57
WEST INT HUB	$34.01	$35.75	$1.74
WESTERN HUB	$34.10	$36.01	$1.91

Table 14 shows the zonal load-weighted average LMP increases.

Table 14 PJM load-weighted average LMP by zone: 2018, Case A to Case C

	Load Weighted LMP ($/MWh)		
	Case A	Case C	Difference
AECO	$36.31	$38.30	$1.99
AEP	$35.36	$37.17	$1.80
AP	$36.59	$38.62	$2.03
ATSI	$35.98	$37.71	$1.74
BGE	$40.04	$42.63	$2.59
COMED	$29.47	$31.15	$1.68
CPP	$34.87	$36.21	$1.34
DAY	$35.17	$36.97	$1.79
DEOK	$34.74	$36.61	$1.87
DOM	$39.25	$41.56	$2.31
DPL	$39.62	$41.72	$2.10
DUQ	$35.67	$37.42	$1.75
EKPC	$34.44	$36.28	$1.84
JCPL	$36.23	$38.22	$1.99
METED	$36.63	$38.55	$1.93
PECO	$35.89	$37.98	$2.09
PENELEC	$35.67	$37.46	$1.80
PEPCO	$38.96	$41.35	$2.39
PPL	$35.73	$37.77	$2.04
PSEG	$35.84	$37.72	$1.88

Table 15 shows the increases in energy prices at generation pricing nodes.

Table 15 PJM generation-weighted average LMP by zone: 2018, Case A to Case C

	Generation Weighted LMP ($/MWh)		
	Case A	Case C	Difference
AECO	$35.67	$37.55	$1.89
AEP	$32.25	$33.91	$1.65
AP	$33.90	$35.75	$1.85
ATSI	$34.66	$36.45	$1.79
BGE	$39.54	$42.30	$2.77
COMED	$27.39	$29.36	$1.96
DAY	$37.03	$39.46	$2.43
DEOK	$32.40	$33.94	$1.54
DOM	$38.59	$40.85	$2.26
DPL	$41.79	$45.12	$3.34
DUQ	$34.41	$36.14	$1.73
EKPC	$34.99	$36.87	$1.88
JCPL	$32.66	$34.24	$1.58
METED	$32.61	$34.45	$1.85
OVEC	$30.59	$31.80	$1.21
PECO	$33.39	$35.18	$1.79
PENELEC	$33.60	$35.37	$1.77
PEPCO	$41.00	$44.50	$3.50
PPL	$33.79	$35.81	$2.02
PSEG	$33.55	$35.21	$1.66

Table 16 shows the increases in reserve prices. Both synchronized reserve and primary reserve prices are more than three times higher in Case C than in Case A.

Table 16 Monthly PJM reserve market prices: 2018, Case A to Case C

	Reserve Weighted Average Market Clearing Prices ($/MW)					
	Case A		Case C		Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	$4.55	$1.28	$15.80	$6.66	$11.25	$5.39
Feb	$1.03	$0.16	$6.65	$2.57	$5.62	$2.41
Mar	$2.42	$1.17	$6.71	$3.04	$4.29	$1.87
Apr	$4.34	$2.37	$7.90	$3.87	$3.56	$1.50
May	$2.82	$1.07	$5.82	$2.82	$2.99	$1.75
Jun	$0.97	$0.74	$3.74	$2.30	$2.77	$1.56
Jul	$1.12	$0.84	$4.11	$2.25	$2.99	$1.41
Aug	$0.73	$0.43	$3.59	$1.89	$2.86	$1.46
Sep	$1.48	$1.25	$4.23	$2.82	$2.75	$1.57
Oct	$2.00	$1.66	$6.04	$3.83	$4.05	$2.17
Nov	$1.68	$0.98	$5.92	$3.13	$4.24	$2.15
Dec	$0.71	$0.50	$5.46	$2.89	$4.75	$2.39
Annual	$1.99	$1.03	$6.33	$3.21	$4.34	$2.18

Table 17 shows monthly reserve market clearing results. Case A and Case B clear similar amounts of reserves, so the difference between Case A and Case C is very similar to the difference between Case B and Case C.

Table 17 Monthly PJM reserve market clearing: 2018, Case A to Case C

	Cleared Reserve MWh							
	Case A		Case C		Difference		Percent Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	1,330,584.2	462,676.8	2,418,397.5	546,578.3	1,087,813.3	83,901.5	81.8%	18.1%
Feb	1,104,579.5	424,887.5	2,130,543.1	507,781.1	1,025,963.6	82,893.6	92.9%	19.5%
Mar	1,320,385.9	480,314.2	2,040,335.0	508,224.3	719,949.2	27,910.2	54.5%	5.8%
Apr	1,242,293.3	444,113.1	1,875,125.5	478,559.4	632,832.2	34,446.3	50.9%	7.8%
May	1,224,815.1	450,454.2	1,926,473.6	487,224.9	701,658.5	36,770.7	57.3%	8.2%
Jun	1,259,202.4	416,355.6	2,259,288.5	423,859.6	1,000,086.1	7,504.0	79.4%	1.8%
Jul	1,311,503.4	484,657.4	2,367,598.0	507,157.2	1,056,094.6	22,499.8	80.5%	4.6%
Aug	1,298,832.7	481,676.6	2,377,283.8	512,919.8	1,078,451.1	31,243.2	83.0%	6.5%
Sep	1,307,345.4	372,256.5	2,329,466.3	378,763.9	1,022,120.9	6,507.5	78.2%	1.7%
Oct	1,462,599.6	435,356.9	2,450,038.5	438,649.3	987,438.9	3,292.4	67.5%	0.8%
Nov	1,310,571.2	471,254.9	2,278,685.6	489,567.6	968,114.4	18,312.7	73.9%	3.9%
Dec	1,315,103.5	482,949.9	2,532,455.1	494,226.7	1,217,351.6	11,276.8	92.6%	2.3%
Total	15,487,815.9	5,406,953.4	26,985,690.1	5,773,512.0	11,497,874.2	366,558.6	74.2%	6.8%

Table 18 provides the monthly generator revenue comparison for Case A and Case C. Total generator revenues increase from Case A to Case C by $1.7 billion. Increased energy revenues account for 90.8 percent of the increase and increased synchronized reserve payments account for 8.4 percent. The increase in generator revenues is more than $1 billion higher when comparing Case C to Case A than when comparing Case B to Case C.

Table 18 Monthly PJM generator revenue: 2018, Case A to Case C

	Revenue ($)												
	Case A				Case C				Difference				
	Generation	SR	PR	OR	Generation	SR	PR	OR	Generation	SR	PR	OR
Jan	$4,721,942,931.8	$6,059,690.0	$590,123.9	$0.0	$5,179,435,042.5	$38,219,472.1	$3,640,986.1	$6,807.5	$457,492,110.7	$32,159,782.1	$3,050,862.3	$6,807.5
Feb	$1,415,723,162.9	$1,141,654.3	$68,865.7	$0.0	$1,543,724,380.7	$14,175,045.2	$1,307,337.2	$0.0	$128,001,217.8	$13,033,390.9	$1,238,471.6	$0.0
Mar	$1,747,326,457.6	$3,196,953.8	$563,993.6	$0.0	$1,880,105,031.9	$13,687,271.3	$1,546,359.5	$0.0	$132,778,574.3	$10,490,317.6	$982,365.9	$0.0
Apr	$1,772,922,354.2	$5,387,102.6	$1,053,933.7	$0.0	$1,859,479,992.5	$14,809,220.0	$1,853,779.5	$0.0	$86,557,638.3	$9,422,117.5	$799,845.8	$0.0
May	$1,708,618,722.9	$3,458,761.1	$482,879.6	$0.0	$1,796,050,045.9	$11,202,492.5	$1,372,517.0	$0.0	$87,431,323.0	$7,743,731.5	$889,637.5	$0.0
Jun	$1,847,286,164.8	$1,220,012.8	$307,677.3	$0.0	$1,958,510,650.6	$8,451,910.9	$976,354.2	$0.0	$111,224,485.8	$7,231,898.1	$668,676.9	$0.0
Jul	$2,505,939,506.7	$1,468,835.0	$405,465.1	$0.0	$2,604,621,249.7	$9,728,911.1	$1,140,853.8	$0.0	$98,681,743.0	$8,260,076.1	$735,388.7	$0.0
Aug	$2,691,708,750.5	$944,817.0	$205,406.4	$0.0	$2,768,400,772.2	$8,531,431.0	$967,552.5	$0.0	$76,692,021.7	$7,586,614.0	$762,146.1	$0.0
Sep	$2,165,046,703.9	$1,935,343.8	$466,280.8	$0.0	$2,234,089,436.4	$9,855,606.3	$1,067,524.7	$0.0	$69,042,732.5	$7,920,262.5	$601,243.9	$0.0
Oct	$1,960,059,046.6	$2,923,290.1	$722,045.5	$0.0	$2,062,113,922.3	$14,807,457.1	$1,680,044.1	$0.0	$102,054,875.7	$11,884,167.0	$957,998.7	$0.0
Nov	$2,228,604,987.3	$2,198,883.6	$461,822.2	$0.0	$2,305,248,950.4	$13,485,785.4	$1,531,255.5	$0.0	$76,643,963.1	$11,286,901.8	$1,069,433.3	$0.0
Dec	$2,031,396,902.8	$931,137.4	$241,804.3	$0.0	$2,120,810,211.0	$13,815,461.4	$1,427,978.3	$0.0	$89,413,308.2	$12,884,324.0	$1,186,173.9	$0.0
Total	$26,796,575,692.0	$30,866,481.3	$5,570,298.0	$0.0	$28,312,589,686.1	$170,770,064.5	$18,512,542.5	$6,807.5	$1,516,013,994.1	$139,903,583.2	$12,942,244.5	$6,807.5

Table 19 shows the increases in revenues by generator technology from Case A to Case C. Table 20 shows the increases in revenues by generator per ICAP MW by generator technology from Case A to Case C. The nuclear units receive the largest increase in revenues because the energy revenues account for a larger share of the revenue increase from Case A to Case C, compared to Case B to Case C.

Table 19 Generator revenues by technology type: 2018, Case A to Case C

	Revenue ($)								
	Case A			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$144,174.4	$0.0	$0.0	$151,937.2	$533.1	$55.4	$7,762.7	$533.1	$55.4
CC	$7,484,861,343.8	$17,275,747.1	$539.5	$7,834,745,587.7	$95,559,023.1	$4,333.1	$349,884,243.9	$78,283,276.0	$3,793.6
CT Natural Gas	$805,127,285.3	$4,795,045.9	$1,616,514.3	$926,170,750.9	$26,927,506.5	$6,407,041.0	$121,043,465.5	$22,132,460.6	$4,790,526.7
CT Oil	$39,567,721.2	$1,470,433.3	$3,708,429.6	$46,963,248.8	$5,005,884.6	$11,325,661.7	$7,395,527.5	$3,535,451.3	$7,617,232.1
CT Other	$5,669,809.6	$8,580.7	$19,434.9	$5,975,629.3	$41,186.5	$60,698.1	$305,819.7	$32,605.8	$41,263.2
Fuel Cell	$7,146,807.5	$0.0	$0.0	$7,556,319.5	$0.0	$0.0	$409,511.9	$0.0	$0.0
Hydro	$467,552,732.7	$2,305,817.9	$87,871.0	$489,809,456.5	$9,556,905.8	$265,559.0	$22,256,723.8	$7,251,087.8	$177,688.0
Nuclear	$8,624,960,212.6	$0.0	$0.0	$9,160,068,376.6	$0.0	$0.0	$535,108,164.0	$0.0	$0.0
RICE Natural Gas	$13,132,167.2	$65,537.6	$0.0	$14,478,100.4	$461,374.5	$0.0	$1,345,933.1	$395,837.0	$0.0
RICE Oil	$1,301,349.6	$1,957.5	$87,485.9	$1,401,120.9	$7,445.1	$264,985.1	$99,771.4	$5,487.6	$177,499.1
RICE Other	$51,181,770.3	$378,016.8	$46,956.6	$53,795,291.6	$1,397,551.4	$141,371.5	$2,613,521.2	$1,019,534.6	$94,414.9
Solar	$63,794,993.7	$0.0	$0.0	$67,156,170.0	$0.0	$0.0	$3,361,176.3	$0.0	$0.0
Steam Coal	$8,107,721,991.6	$3,817,694.2	$2,868.2	$8,530,672,556.5	$28,365,453.2	$42,837.5	$422,950,564.9	$24,547,759.1	$39,969.3
Steam Natural Gas	$282,552,561.3	$537,800.2	$197.9	$278,003,548.3	$2,641,350.2	$0.0	($4,549,013.0)	$2,103,550.0	($197.9)
Steam Oil	$38,694,864.0	$44,166.4	$0.0	$40,905,504.0	$187,324.2	$0.0	$2,210,640.0	$143,157.8	$0.0
Steam Other	$221,652,709.9	$165,093.6	$0.0	$233,449,453.0	$616,857.5	$0.0	$11,796,743.2	$451,764.0	$0.0
Wind	$581,516,370.5	$0.0	$0.0	$621,289,059.6	$0.0	$0.0	$39,772,689.1	$0.0	$0.0
Total	$26,796,578,865.2	$30,865,891.2	$5,570,298.0	$28,312,592,110.7	$170,768,395.8	$18,512,542.5	$1,516,013,245.4	$139,902,504.6	$12,942,244.5

Table 20 Generator revenues per ICAP MW by technology type: 2018, Case A to Case C

	Revenue ($/MW)								
	Case A			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$3,604.36	$0.00	$0.00	$3,798.43	$13.33	$1.38	$194.07	$13.33	$1.38
CC	$155,967.75	$359.99	$0.01	$163,258.56	$1,991.24	$0.09	$7,290.80	$1,631.25	$0.08
CT Natural Gas	$32,156.09	$191.51	$64.56	$36,990.46	$1,075.46	$255.89	$4,834.37	$883.95	$191.33
CT Oil	$9,983.78	$371.02	$935.72	$11,849.83	$1,263.09	$2,857.71	$1,866.05	$892.07	$1,921.99
CT Other	$127,698.41	$193.26	$437.72	$134,586.24	$927.62	$1,367.07	$6,887.83	$734.36	$929.35
Fuel Cell	$238,226.92	$0.00	$0.00	$251,877.32	$0.00	$0.00	$13,650.40	$0.00	$0.00
Hydro	$57,912.74	$285.61	$10.88	$60,669.54	$1,183.75	$32.89	$2,756.80	$898.15	$22.01
Nuclear	$247,331.25	$0.00	$0.00	$262,676.13	$0.00	$0.00	$15,344.88	$0.00	$0.00
RICE Natural Gas	$109,071.16	$544.33	$0.00	$120,250.00	$3,832.01	$0.00	$11,178.85	$3,287.68	$0.00
RICE Oil	$5,665.43	$8.52	$380.87	$6,099.79	$32.41	$1,153.61	$434.36	$23.89	$772.74
RICE Other	$141,785.61	$1,047.20	$130.08	$149,025.68	$3,871.55	$391.63	$7,240.07	$2,824.35	$261.55
Solar	$45,967.24	$0.00	$0.00	$48,389.13	$0.00	$0.00	$2,421.88	$0.00	$0.00
Steam Coal	$125,943.83	$59.30	$0.04	$132,513.86	$440.62	$0.67	$6,570.03	$381.32	$0.62
Steam Natural Gas	$28,178.89	$53.63	$0.02	$27,725.22	$263.42	$0.00	($453.67)	$209.79	($0.02)
Steam Oil	$16,867.86	$19.25	$0.00	$17,831.52	$81.66	$0.00	$963.66	$62.41	$0.00
Steam Other	$186,497.86	$138.91	$0.00	$196,423.60	$519.02	$0.00	$9,925.74	$380.11	$0.00
Wind	$64,478.96	$0.00	$0.00	$68,888.98	$0.00	$0.00	$4,410.02	$0.00	$0.00
Total	$128,180.23	$147.65	$26.65	$135,432.01	$816.86	$88.55	$7,251.78	$669.22	$61.91

To estimate the increase in carbon dioxide emissions due to the ORDC, the emissions rate for each technology, as calculated by the EIA, is multiplied by a generic heat rate for the technology and the simulated MWh of energy.[6] Table 21 provides the estimated increase in CO_2 emissions in short tons. For Case A to Case C, the total MWh used to serve load decreases, so the total emissions also fall.

[6] Carbon Dioxide Emissions Coefficients, Energy Information Administration, <https://www.eia.gov/environment/emissions/co2_vol_mass.php>, accessed May 9, 2019.

Table 21 Estimated emissions change: 2018, Case A to Case C

	CO2 Rate (lbs/MMBtu)	Heat Rate (MMBtu/MWh)	CO2 Rate (tons/MWh)	CO2 Case A (tons)	CO2 Case C (tons)	CO2 Difference (tons)
Battery						
CC	117.00	7.5	0.44	99,921,281	99,450,170	(471,111)
CT Natural Gas	117.00	11.0	0.64	10,126,406	11,471,605	1,345,199
CT Oil	161.30	13.0	1.05	228,427	246,871	18,444
CT Other	117.00	11.0	0.64	106,225	106,192	(32)
Fuel Cell						
Hydro						
Nuclear						
RICE Natural Gas	117.00	11.0	0.64	191,070	209,061	17,991
RICE Oil	161.30	13.0	1.05	9,573	9,543	(31)
RICE Other	117.00	11.0	0.64	947,109	947,067	(41)
Solar						
Steam Coal	210.20	11.0	1.16	271,630,534	271,055,453	(575,081)
Steam Natural Gas	117.00	11.0	0.64	3,809,895	3,366,226	(443,669)
Steam Oil	161.30	11.0	0.89	296,370	288,764	(7,606)
Steam Other	117.00	11.0	0.64	4,089,342	4,074,302	(15,039)
Wind						
Total				387,266,889	387,150,952	(115,936)

Case A to Case A ORDC

The Market Monitor also compares Case A to Case A ORDC. The Case A ORDC adds PJM's ORDC directly to the Case A model rather than to the Case B model.

Table 22 shows that the LMP increase between Case A and Case A ORDC is $1.12 per MWh. This is lower than the $1.96 per MWh LMP increase between Case A and Case C, and greater than the $0.46 per MWh increase between Case B and Case C.

Table 22 PJM load-weighted average LMP: 2018, Case A to Case A ORDC

	Load Weighted LMP ($/MWh)		
	Case A	Case A ORDC	Difference
Jan	$68.39	$70.74	$2.34
Feb	$25.67	$27.26	$1.59
Mar	$28.82	$29.58	$0.76
Apr	$33.19	$34.18	$0.99
May	$30.80	$31.45	$0.65
Jun	$28.75	$29.31	$0.56
Jul	$33.64	$34.07	$0.43
Aug	$35.42	$36.01	$0.59
Sep	$34.73	$35.46	$0.73
Oct	$32.92	$34.16	$1.25
Nov	$36.87	$38.27	$1.40
Dec	$32.37	$34.49	$2.12
Total	$35.80	$36.91	$1.12

Table 23 provides average energy prices for the PJM hubs for Case A and Case A with the PJM proposed ORDC.

Table 23 Average hub LMP: 2018, Case A to Case A ORDC

	Average LMP ($/MWh)		
	Case A	Case A ORDC	Difference
AEP GEN HUB	$31.08	$32.11	$1.03
AEP-DAYTON HUB	$32.43	$33.47	$1.04
ATSI GEN HUB	$33.18	$34.28	$1.10
CHICAGO GEN HUB	$27.39	$28.30	$0.91
CHICAGO HUB	$27.97	$28.89	$0.92
DOMINION HUB	$35.66	$36.68	$1.02
EASTERN HUB	$35.78	$36.98	$1.19
N ILLINOIS HUB	$27.77	$28.68	$0.92
NEW JERSEY HUB	$33.69	$34.86	$1.17
OHIO HUB	$32.21	$33.25	$1.04
WEST INT HUB	$34.01	$35.06	$1.04
WESTERN HUB	$34.10	$35.18	$1.07

Table 24 and Table 25 provide the increases in load and generation-weighted average energy prices by zone when PJM's proposed ORDC is applied to Case A.

Table 24 PJM load-weighted average LMP by zone: 2018, Case A to Case A ORDC

	Load Weighted LMP ($/MWh)		
	Case A	Case A1	Difference
AECO	$36.31	$37.53	$1.22
AEP	$35.36	$36.45	$1.09
AP	$36.59	$37.74	$1.15
ATSI	$35.98	$37.13	$1.15
BGE	$40.04	$41.11	$1.07
COMED	$29.47	$30.41	$0.94
CPP	$34.87	$36.46	$1.58
DAY	$35.17	$36.32	$1.14
DEOK	$34.74	$35.86	$1.12
DOM	$39.25	$40.34	$1.09
DPL	$39.62	$40.88	$1.26
DUQ	$35.67	$36.80	$1.12
EKPC	$34.44	$35.55	$1.11
JCPL	$36.23	$37.45	$1.22
METED	$36.63	$37.83	$1.21
PECO	$35.89	$37.13	$1.23
PENELEC	$35.67	$36.88	$1.21
PEPCO	$38.96	$40.03	$1.07
PPL	$35.73	$36.96	$1.22
PSEG	$35.84	$37.02	$1.18

Table 25 PJM generation-weighted average LMP by zone: 2018, Case A to Case A ORDC

	Generation Weighted LMP ($/MWh)		
	Case A	Case A ORDC	Difference
AECO	$35.67	$36.83	$1.16
AEP	$32.25	$33.31	$1.05
AP	$33.90	$34.99	$1.09
ATSI	$34.66	$35.85	$1.19
BGE	$39.54	$40.56	$1.03
COMED	$27.39	$28.32	$0.93
DAY	$37.03	$38.45	$1.42
DEOK	$32.40	$33.48	$1.08
DOM	$38.59	$39.67	$1.08
DPL	$41.79	$43.17	$1.39
DUQ	$34.41	$35.51	$1.11
EKPC	$34.99	$36.17	$1.18
JCPL	$32.66	$33.75	$1.10
METED	$32.61	$33.78	$1.17
OVEC	$30.59	$32.65	$2.06
PECO	$33.39	$34.62	$1.23
PENELEC	$33.60	$34.86	$1.26
PEPCO	$41.00	$42.11	$1.12
PPL	$33.79	$34.98	$1.20
PSEG	$33.55	$34.72	$1.16

Table 26 shows the increases in reserve prices when the PJM proposed ORDC is applied to Case A.

Table 26 Monthly PJM reserve market prices: 2018, Case A to Case A ORDC

	Reserve Weighted Average Market Clearing Prices ($/MW)					
	Case A		Case A ORDC		Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	$4.55	$1.28	$14.44	$6.11	$9.88	$4.84
Feb	$1.03	$0.16	$6.49	$2.53	$5.46	$2.37
Mar	$2.42	$1.17	$5.56	$2.47	$3.14	$1.30
Apr	$4.34	$2.37	$7.55	$3.71	$3.22	$1.34
May	$2.82	$1.07	$5.60	$2.70	$2.78	$1.63
Jun	$0.97	$0.74	$3.20	$2.00	$2.23	$1.26
Jul	$1.12	$0.84	$3.72	$2.06	$2.60	$1.22
Aug	$0.73	$0.43	$3.47	$1.85	$2.75	$1.42
Sep	$1.48	$1.25	$4.21	$2.82	$2.73	$1.56
Oct	$2.00	$1.66	$5.97	$3.78	$3.97	$2.12
Nov	$1.68	$0.98	$5.92	$3.17	$4.24	$2.19
Dec	$0.71	$0.50	$6.26	$3.37	$5.55	$2.87
Annual	$1.99	$1.03	$6.05	$3.08	$4.05	$2.05

Table 27 shows the monthly reserve clearing levels when the PJM proposed ORDC is applied to Case A.

Table 27 Monthly PJM reserve market clearing: 2018, Case A to Case A ORDC

	Cleared Reserve MWh							
	Case A		Case A ORDC		Difference		Percent Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	1,330,584.2	462,676.8	2,445,062.7	548,353.4	1,114,478.5	85,676.6	83.8%	18.5%
Feb	1,104,579.5	424,887.5	2,138,010.4	507,611.7	1,033,430.9	82,724.1	93.6%	19.5%
Mar	1,320,385.9	480,314.2	2,096,359.6	508,626.9	775,973.7	28,312.8	58.8%	5.9%
Apr	1,242,293.3	444,113.1	1,886,322.7	478,023.9	644,029.4	33,910.8	51.8%	7.6%
May	1,224,815.1	450,454.2	1,938,602.6	487,486.4	713,787.5	37,032.3	58.3%	8.2%
Jun	1,259,202.4	416,355.6	2,286,218.0	424,304.8	1,027,015.6	7,949.2	81.6%	1.9%
Jul	1,311,503.4	484,657.4	2,387,740.2	508,090.9	1,076,236.8	23,433.5	82.1%	4.8%
Aug	1,298,832.7	481,676.6	2,387,116.6	512,981.3	1,088,283.9	31,304.7	83.8%	6.5%
Sep	1,307,345.4	372,256.5	2,335,838.7	379,079.1	1,028,493.3	6,822.7	78.7%	1.8%
Oct	1,462,599.6	435,356.9	2,456,927.0	439,048.7	994,327.4	3,691.8	68.0%	0.8%
Nov	1,310,571.2	471,254.9	2,291,506.6	489,321.5	980,935.4	18,066.6	74.8%	3.8%
Dec	1,315,103.5	482,949.9	2,525,861.3	494,245.9	1,210,757.8	11,296.0	92.1%	2.3%
Total	15,487,815.9	5,406,953.4	27,175,566.0	5,777,174.3	11,687,750.1	370,221.0	75.5%	6.8%

Table 28 shows the increases in generator revenue when PJM's proposed ORDC is applied to Case A.

Table 28 Monthly PJM generator revenue: 2018, Case A to Case A ORDC

	Revenue ($)											
	Case A				Case A ORDC				Difference			
	Generation	SR	PR	OR	Generation	SR	PR	OR	Generation	SR	PR	OR
Jan	$4,721,942,931.8	$6,059,690.0	$590,123.9	$0.0	$4,903,702,907.4	$35,303,787.8	$3,352,958.5	$6,853.3	$181,759,975.6	$29,244,097.9	$2,762,834.6	$6,853.3
Feb	$1,415,723,162.9	$1,141,654.3	$68,865.7	$0.0	$1,505,390,913.7	$13,879,148.9	$1,284,741.5	$0.0	$89,667,750.8	$12,737,494.6	$1,215,875.8	$0.0
Mar	$1,747,326,457.6	$3,196,953.8	$563,993.6	$0.0	$1,793,996,326.8	$11,661,958.2	$1,257,380.7	$0.0	$46,669,869.2	$8,465,004.5	$693,387.1	$0.0
Apr	$1,772,922,354.2	$5,387,102.6	$1,053,933.7	$0.0	$1,827,296,170.8	$14,247,039.3	$1,775,546.7	$0.0	$54,373,816.6	$8,859,936.7	$721,613.0	$0.0
May	$1,708,618,722.9	$3,458,761.1	$482,879.6	$0.0	$1,747,120,599.4	$10,865,845.1	$1,316,140.9	$0.0	$38,501,876.5	$7,407,084.1	$833,261.4	$0.0
Jun	$1,847,286,164.8	$1,220,012.8	$307,677.3	$0.0	$1,884,384,743.0	$7,316,486.5	$848,315.9	$0.0	$37,098,578.2	$6,096,473.7	$540,638.6	$0.0
Jul	$2,505,939,506.7	$1,468,835.0	$405,465.1	$0.0	$2,539,745,703.8	$8,890,634.9	$1,044,746.0	$0.0	$33,806,197.1	$7,421,800.0	$639,280.9	$0.0
Aug	$2,691,708,750.5	$944,817.0	$205,406.4	$0.0	$2,738,981,078.8	$8,294,350.9	$948,480.0	$0.0	$47,272,328.3	$7,349,534.0	$743,073.6	$0.0
Sep	$2,165,046,703.9	$1,935,343.8	$466,280.8	$0.0	$2,217,133,432.6	$9,834,664.3	$1,067,937.8	$0.0	$52,086,728.7	$7,899,320.5	$601,657.1	$0.0
Oct	$1,960,059,046.6	$2,923,290.1	$722,045.5	$0.0	$2,037,984,679.1	$14,665,751.7	$1,660,008.2	$0.0	$77,925,632.5	$11,742,461.7	$937,962.8	$0.0
Nov	$2,228,604,987.3	$2,198,883.6	$461,822.2	$0.0	$2,317,394,164.9	$13,568,427.3	$1,549,689.7	$0.0	$88,789,177.6	$11,369,543.7	$1,087,867.5	$0.0
Dec	$2,031,396,902.8	$931,137.4	$241,804.3	$0.0	$2,166,214,528.6	$15,817,395.2	$1,667,131.7	$0.0	$134,817,625.8	$14,886,257.9	$1,425,327.4	$0.0
Total	$26,796,575,692.0	$30,866,481.3	$5,570,298.0	$0.0	$27,679,345,248.9	$164,345,490.4	$17,773,077.7	$6,853.3	$882,769,556.9	$133,479,009.0	$12,202,779.7	$6,853.3

Table 29 and Table 30 show the generator revenues by technology type, both total and per ICAP MW, comparing Case A to Case A with the PJM proposed ORDC.

Table 29 Generator revenues by technology type: 2018, Case A to Case A ORDC

	Revenue ($)								
	Case A			Case A1			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$144,174.4	$0.0	$0.0	$155,536.6	$277.1	$55.4	$11,362.2	$277.1	$55.4
CC	$7,484,861,343.8	$17,275,747.1	$539.5	$7,680,684,082.1	$90,320,363.5	$5,000.2	$195,822,738.3	$73,044,616.4	$4,460.7
CT Natural Gas	$805,127,285.3	$4,795,045.9	$1,616,514.3	$869,483,702.5	$26,359,623.3	$6,093,503.0	$64,356,417.2	$21,564,577.4	$4,476,988.7
CT Oil	$39,567,721.2	$1,470,433.3	$3,708,429.6	$40,491,904.3	$5,023,324.6	$10,939,062.3	$924,183.1	$3,552,891.3	$7,230,632.7
CT Other	$5,669,809.6	$8,580.7	$19,434.9	$5,845,941.0	$41,415.9	$56,705.1	$176,131.5	$32,835.2	$37,270.2
Fuel Cell	$7,146,807.5	$0.0	$0.0	$7,403,493.9	$0.0	$0.0	$256,686.3	$0.0	$0.0
Hydro	$467,552,732.7	$2,305,817.9	$87,871.0	$486,117,032.0	$9,186,724.4	$250,957.8	$18,564,299.3	$6,880,906.5	$163,086.9
Nuclear	$8,624,960,212.6	$0.0	$0.0	$8,916,012,522.1	$0.0	$0.0	$291,052,309.6	$0.0	$0.0
RICE Natural Gas	$13,132,167.2	$65,537.6	$0.0	$14,252,185.1	$477,897.2	$0.0	$1,120,017.9	$412,359.7	$0.0
RICE Oil	$1,301,349.6	$1,957.5	$87,485.9	$1,320,746.6	$8,381.2	$248,170.9	$19,397.0	$6,423.7	$160,685.0
RICE Other	$51,181,770.3	$378,016.8	$46,956.6	$52,643,347.3	$1,341,552.8	$135,816.5	$1,461,577.0	$963,536.0	$88,859.9
Solar	$63,794,993.7	$0.0	$0.0	$65,510,189.5	$0.0	$0.0	$1,715,195.8	$0.0	$0.0
Steam Coal	$8,107,721,991.6	$3,817,694.2	$2,868.2	$8,378,605,491.7	$28,082,751.7	$43,579.2	$270,883,500.1	$24,265,057.5	$40,710.9
Steam Natural Gas	$282,552,561.3	$537,800.2	$197.9	$289,145,179.8	$2,736,022.3	$227.2	$6,592,618.5	$2,198,222.1	$29.3
Steam Oil	$38,694,864.0	$44,166.4	$0.0	$39,328,394.9	$185,138.6	$0.0	$633,530.8	$140,972.2	$0.0
Steam Other	$221,652,709.9	$165,093.6	$0.0	$228,374,231.0	$580,406.5	$0.0	$6,721,521.1	$415,312.9	$0.0
Wind	$581,516,370.5	$0.0	$0.0	$603,972,118.5	$0.0	$0.0	$22,455,748.0	$0.0	$0.0
Total	$26,796,578,865.2	$30,865,891.2	$5,570,298.0	$27,679,346,098.9	$164,343,879.0	$17,773,077.7	$882,767,233.7	$133,477,987.8	$12,202,779.7

Table 30 Generator revenue per ICAP MW by technology type: 2018, Case A to Case A ORDC

	Revenue ($/MW-year)								
	Case A			Case C			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$3,604.36	$0.00	$0.00	$3,798.43	$13.33	$1.38	$194.07	$13.33	$1.38
CC	$155,967.75	$359.99	$0.01	$163,258.56	$1,991.24	$0.09	$7,290.80	$1,631.25	$0.08
CT Natural Gas	$32,156.09	$191.51	$64.56	$36,990.46	$1,075.46	$255.89	$4,834.37	$883.95	$191.33
CT Oil	$9,983.78	$371.02	$935.72	$11,849.83	$1,263.09	$2,857.71	$1,866.05	$892.07	$1,921.99
CT Other	$127,698.41	$193.26	$437.72	$134,586.24	$927.62	$1,367.07	$6,887.83	$734.36	$929.35
Fuel Cell	$238,226.92	$0.00	$0.00	$251,877.32	$0.00	$0.00	$13,650.40	$0.00	$0.00
Hydro	$57,912.74	$285.61	$10.88	$60,669.54	$1,183.75	$32.89	$2,756.80	$898.15	$22.01
Nuclear	$247,331.25	$0.00	$0.00	$262,676.13	$0.00	$0.00	$15,344.88	$0.00	$0.00
RICE Natural Gas	$109,071.16	$544.33	$0.00	$120,250.00	$3,832.01	$0.00	$11,178.85	$3,287.68	$0.00
RICE Oil	$5,665.43	$8.52	$380.87	$6,099.79	$32.41	$1,153.61	$434.36	$23.89	$772.74
RICE Other	$141,785.61	$1,047.20	$130.08	$149,025.68	$3,871.55	$391.63	$7,240.07	$2,824.35	$261.55
Solar	$45,967.24	$0.00	$0.00	$48,389.13	$0.00	$0.00	$2,421.88	$0.00	$0.00
Steam Coal	$125,943.83	$59.30	$0.04	$132,513.86	$440.62	$0.67	$6,570.03	$381.32	$0.62
Steam Natural Gas	$28,178.89	$53.63	$0.02	$27,725.22	$263.42	$0.00	($453.67)	$209.79	($0.02)
Steam Oil	$16,867.86	$19.25	$0.00	$17,831.52	$81.66	$0.00	$963.66	$62.41	$0.00
Steam Other	$186,497.86	$138.91	$0.00	$196,423.60	$519.02	$0.00	$9,925.74	$380.11	$0.00
Wind	$64,478.96	$0.00	$0.00	$68,888.98	$0.00	$0.00	$4,410.02	$0.00	$0.00
Total	$128,180.23	$147.65	$26.65	$135,432.01	$816.86	$88.55	$7,251.78	$669.22	$61.91

To estimate the increase in carbon dioxide emissions due to the ORDC, the emissions rate for each technology, as calculated by the EIA, is multiplied by a generic heat rate for the technology and the simulated MWh of energy.[7] Table 31 provides the estimated increase in CO_2 emissions in short tons.

[7] Carbon Dioxide Emissions Coefficients, Energy Information Administration, <https://www.eia.gov/environment/emissions/co2_vol_mass.php>, accessed May 9, 2019.

Table 31 Estimated emissions increase: 2018, Case A to Case A ORDC

	CO2 Rate (lbs/MMBtu)	Heat Rate (MMBtu/MWh)	CO2 Rate (tons/MWh)	CO2 Case A (tons)	CO2 Case A ORDC (tons)	CO2 Difference (tons)
Battery						
CC	117.00	7.5	0.44	99,921,281	99,218,180	(703,101)
CT Natural Gas	117.00	11.0	0.64	10,126,406	10,842,983	716,577
CT Oil	161.30	13.0	1.05	228,427	230,241	1,814
CT Other	117.00	11.0	0.64	106,225	106,182	(42)
Fuel Cell						
Hydro						
Nuclear						
RICE Natural Gas	117.00	11.0	0.64	191,070	206,866	15,797
RICE Oil	161.30	13.0	1.05	9,573	9,550	(23)
RICE Other	117.00	11.0	0.64	947,109	946,662	(447)
Solar						
Steam Coal	210.20	11.0	1.16	271,630,534	272,133,017	502,483
Steam Natural Gas	117.00	11.0	0.64	3,809,895	3,814,332	4,437
Steam Oil	161.30	11.0	0.89	296,370	295,936	(434)
Steam Other	117.00	11.0	0.64	4,089,342	4,088,432	(909)
Wind						
Total				387,266,889	387,803,950	537,061

Case B to Case C 15 minute

When PJM's 30 minute ORDC is replaced with an ORDC based on 15 minute forecast error uncertainty, the price and revenue differences are lower.

Table 32 shows the increase in monthly energy prices between Case B and Case C 15 minute.

Table 32 PJM load-weighted average LMP: 2018, Case B to Case C 15 minute

	Load Weighted LMP ($/MWh)		
	Case B	Case C15	Difference
Jan	$73.87	$74.91	$1.04
Feb	$27.58	$27.88	$0.30
Mar	$30.64	$30.73	$0.09
Apr	$34.10	$34.47	$0.37
May	$31.96	$32.13	$0.17
Jun	$30.13	$30.18	$0.05
Jul	$34.53	$34.70	$0.16
Aug	$36.02	$36.15	$0.13
Sep	$35.59	$35.75	$0.16
Oct	$33.90	$34.26	$0.36
Nov	$37.45	$38.02	$0.57
Dec	$33.23	$33.51	$0.28
Total	$37.30	$37.61	$0.31

Table 33 shows the increase in energy prices at PJM hubs. The differences range from $0.13 per MWh to $0.35 per MWh, about $0.15 per MWh less than the differences for Case B to Case C.

Table 33 Average hub LMP: 2018, Case B to Case C 15 minute

	Average LMP ($/MWh)		
	Case B	Case C15	Difference
AEP GEN HUB	$32.20	$32.52	$0.32
AEP-DAYTON HUB	$33.52	$33.85	$0.33
ATSI GEN HUB	$34.40	$34.69	$0.29
CHICAGO GEN HUB	$28.68	$28.94	$0.27
CHICAGO HUB	$29.29	$29.56	$0.27
DOMINION HUB	$37.25	$37.55	$0.30
EASTERN HUB	$37.34	$37.47	$0.13
N ILLINOIS HUB	$29.09	$29.35	$0.27
NEW JERSEY HUB	$35.14	$35.42	$0.28
OHIO HUB	$33.28	$33.61	$0.33
WEST INT HUB	$35.30	$35.61	$0.31
WESTERN HUB	$35.51	$35.86	$0.35

Table 34 and Table 35 show the differences in zonal load and generation-weighted average energy prices.

Table 34 PJM load-weighted average LMP by zone: 2018, Case B to Case C 15 minute

	Load Weighted LMP ($/MWh)		
	Case B	Case C15	Difference
AECO	$37.81	$38.17	$0.36
AEP	$36.65	$36.99	$0.33
AP	$38.12	$38.47	$0.35
ATSI	$37.24	$37.55	$0.31
BGE	$42.13	$42.52	$0.39
COMED	$30.74	$31.03	$0.28
CPP	$35.67	$36.07	$0.40
DAY	$36.44	$36.79	$0.35
DEOK	$36.12	$36.46	$0.34
DOM	$41.06	$41.37	$0.31
DPL	$41.46	$41.59	$0.13
DUQ	$36.95	$37.25	$0.30
EKPC	$35.75	$36.10	$0.35
JCPL	$37.81	$38.11	$0.29
METED	$38.14	$38.44	$0.31
PECO	$37.55	$37.85	$0.30
PENELEC	$36.94	$37.32	$0.38
PEPCO	$40.86	$41.21	$0.35
PPL	$37.40	$37.67	$0.27
PSEG	$37.34	$37.60	$0.26

Table 35 PJM generation-weighted average LMP by zone: 2018, Case B to Case C 15 minute

	Generation Weighted LMP ($/MWh)		
	Case B	Case C15	Difference
AECO	$37.18	$37.42	$0.24
AEP	$33.41	$33.74	$0.33
AP	$35.26	$35.59	$0.33
ATSI	$35.95	$36.28	$0.32
BGE	$41.81	$42.17	$0.35
COMED	$28.99	$29.26	$0.27
DAY	$38.76	$39.28	$0.52
DEOK	$33.44	$33.78	$0.34
DOM	$40.34	$40.65	$0.30
DPL	$44.92	$45.15	$0.23
DUQ	$35.68	$35.97	$0.29
EKPC	$36.29	$36.67	$0.38
JCPL	$33.85	$34.07	$0.23
METED	$34.06	$34.35	$0.29
OVEC	$31.31	$31.63	$0.32
PECO	$34.78	$35.05	$0.27
PENELEC	$34.75	$35.16	$0.41
PEPCO	$43.84	$44.25	$0.42
PPL	$35.42	$35.69	$0.27
PSEG	$34.80	$35.10	$0.30

Table 36 shows the change in reserve clearing prices between Case B and Case C 15 minute. Reserve price increases are high, but they do not more than double as in Case B or Case A to Case C.

Table 36 Monthly PJM reserve market prices: 2018, Case B to Case C 15 minute

	Reserve Weighted Average Market Clearing Prices ($/MW)					
	Case B		Case C 15		Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	$6.03	$1.43	$12.45	$5.25	$6.41	$3.82
Feb	$2.36	$0.31	$5.52	$2.18	$3.16	$1.87
Mar	$3.85	$1.94	$4.63	$1.93	$0.78	($0.01)
Apr	$4.96	$2.47	$5.48	$2.74	$0.52	$0.27
May	$3.20	$1.09	$3.43	$1.67	$0.23	$0.58
Jun	$1.29	$1.06	$2.30	$1.47	$1.01	$0.41
Jul	$1.45	$1.08	$2.77	$1.55	$1.32	$0.47
Aug	$0.81	$0.45	$2.35	$1.26	$1.54	$0.81
Sep	$1.74	$1.47	$3.07	$2.10	$1.34	$0.63
Oct	$2.38	$1.94	$4.51	$2.84	$2.12	$0.90
Nov	$1.93	$1.29	$4.47	$2.41	$2.53	$1.12
Dec	$0.95	$0.59	$4.42	$2.33	$3.47	$1.75
Annual	$2.58	$1.25	$4.66	$2.34	$2.08	$1.09

Table 37 shows that the amount of synchronized reserves cleared with the 15 minute ORDC is much less than the amount cleared with the 30 minute ORDC. The difference in primary reserves changes little.

Table 37 Monthly PJM reserve market clearing: 2018, Case B to Case C 15

	Cleared Reserve MWh							
	Case B		Case C 15		Difference		Percent Difference	
	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve	Synchronized Reserve	Primary Reserve
Jan	1,333,092.8	460,168.2	2,228,540.3	549,776.7	895,447.5	89,608.6	67.2%	19.5%
Feb	1,104,579.4	424,887.5	1,965,775.9	507,575.8	861,196.4	82,688.2	78.0%	19.5%
Mar	1,320,246.7	480,453.2	1,797,395.2	507,862.2	477,148.5	27,409.0	36.1%	5.7%
Apr	1,242,142.7	444,263.6	1,636,792.8	477,526.3	394,650.1	33,262.8	31.8%	7.5%
May	1,224,596.4	450,672.8	1,705,638.6	486,468.2	481,042.2	35,795.4	39.3%	7.9%
Jun	1,260,166.9	415,391.3	2,008,779.8	423,307.1	748,612.9	7,915.8	59.4%	1.9%
Jul	1,311,952.1	484,208.9	2,092,166.6	505,553.7	780,214.6	21,344.8	59.5%	4.4%
Aug	1,298,609.1	481,900.0	2,097,757.4	510,334.8	799,148.3	28,434.8	61.5%	5.9%
Sep	1,307,381.3	372,220.2	2,190,349.4	380,285.2	882,968.1	8,065.0	67.5%	2.2%
Oct	1,462,476.9	435,479.7	2,257,125.9	438,064.3	794,649.0	2,584.6	54.3%	0.6%
Nov	1,310,593.5	471,232.5	2,088,334.8	488,764.7	777,741.2	17,532.3	59.3%	3.7%
Dec	1,315,281.3	482,772.0	2,354,808.2	494,782.0	1,039,526.9	12,009.9	79.0%	2.5%
Total	15,491,118.8	5,403,649.7	24,423,464.6	5,770,300.8	8,932,345.8	366,651.1	57.7%	6.8%

Table 38 provides monthly and annual generator revenue by product. Total generator revenues increase by $329.3 million from Case B to Case C 15 minute.

Table 38 Monthly PJM generator revenue: 2018, Case B to Case C 15

	Revenue ($)											
	Case B				Case C15				Difference			
	Generation	SR	PR	OR	Generation	SR	PR	OR	Generation	SR	PR	OR
Jan	$5,081,623,092.5	$8,041,039.6	$657,447.2	$0.0	$5,164,719,346.6	$27,737,483.1	$2,885,555.4	$13,623.1	$83,096,254.1	$19,696,443.5	$2,228,108.2	$13,623.1
Feb	$1,519,472,468.7	$2,603,153.7	$132,698.2	$0.0	$1,536,564,230.3	$10,850,811.1	$1,108,521.8	$0.0	$17,091,761.6	$8,247,657.4	$975,823.6	$0.0
Mar	$1,859,115,556.6	$5,089,052.2	$933,042.7	$0.0	$1,864,570,295.1	$8,327,706.0	$980,355.9	$0.0	$5,454,738.5	$3,238,653.7	$47,313.2	$0.0
Apr	$1,826,358,822.0	$6,159,167.4	$1,098,624.4	$0.0	$1,846,381,111.9	$8,969,897.6	$1,308,754.1	$14,835.2	$20,022,289.9	$2,810,730.2	$210,129.7	$14,835.2
May	$1,775,298,936.7	$3,915,318.4	$492,517.1	$0.0	$1,784,878,867.9	$5,846,893.8	$812,023.9	$0.0	$9,579,931.2	$1,931,575.3	$319,506.8	$0.0
Jun	$1,935,187,664.6	$1,628,149.4	$439,857.2	$0.0	$1,939,986,706.5	$4,623,571.9	$623,395.9	$0.0	$4,799,041.9	$2,995,422.5	$183,538.7	$0.0
Jul	$2,580,228,898.0	$1,907,918.9	$521,565.1	$0.0	$2,592,662,571.0	$5,800,174.5	$783,547.7	$0.0	$12,433,673.0	$3,892,255.6	$261,982.5	$0.0
Aug	$2,750,194,638.6	$1,050,710.0	$214,835.1	$0.0	$2,761,741,273.6	$4,927,006.9	$642,904.1	$0.0	$11,546,635.0	$3,876,296.8	$428,068.9	$0.0
Sep	$2,222,742,250.0	$2,271,640.2	$546,674.0	$0.0	$2,234,223,570.8	$6,730,050.8	$799,958.9	$0.0	$11,481,320.8	$4,458,410.6	$253,284.9	$0.0
Oct	$2,024,751,056.9	$3,481,601.1	$845,140.1	$0.0	$2,045,976,189.9	$10,168,382.5	$1,246,072.1	$0.0	$21,225,133.0	$6,686,781.4	$400,932.0	$0.0
Nov	$2,273,655,880.6	$2,530,961.9	$608,868.5	$0.0	$2,308,388,830.5	$9,324,641.1	$1,176,746.4	$0.0	$34,732,949.9	$6,793,679.3	$567,877.9	$0.0
Dec	$2,094,561,286.0	$1,254,060.2	$283,817.4	$0.0	$2,111,816,591.9	$10,414,915.4	$1,155,014.1	$0.0	$17,255,305.9	$9,160,855.1	$871,196.6	$0.0
Total	$27,943,190,551.2	$39,932,773.1	$6,775,087.1	$0.0	$28,191,909,586.0	$113,721,534.5	$13,522,850.2	$28,458.3	$248,719,034.8	$73,788,761.3	$6,747,763.1	$28,458.3

Table 39 shows the change in generator revenues by technology with the 15 minute ORDC. Table 40 shows the change in generator revenues per ICAP MW by technology with the 15 minute ORDC. The distribution of increased revenue across technology types is similar to the 30 minute ORDC, but the magnitudes are smaller.

Table 39 Generator revenues by technology type: 2018, Case B to Case C 15 minute

	Revenue ($)								
	Case B			Case C1			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$148,766.5	$0.9	$0.0	$151,503.7	$305.4	$37.9	$2,737.2	$304.5	$37.9
CC	$7,759,725,631.2	$22,947,672.0	$563.7	$7,816,207,204.6	$64,143,239.3	$2,772.2	$56,481,573.4	$41,195,567.3	$2,208.5
CT Natural Gas	$888,699,914.9	$5,773,510.7	$2,003,092.8	$907,809,179.2	$16,306,920.9	$4,707,542.6	$19,109,264.3	$10,533,410.2	$2,704,449.8
CT Oil	$46,324,308.3	$1,690,138.3	$4,474,516.6	$46,794,643.1	$3,550,917.7	$8,249,808.3	$470,334.9	$1,860,779.4	$3,775,291.7
CT Other	$5,899,724.1	$11,965.6	$23,344.2	$5,949,933.6	$30,718.5	$44,295.4	$50,209.6	$18,753.0	$20,951.1
Fuel Cell	$7,469,775.2	$0.0	$0.0	$7,527,969.7	$0.0	$0.0	$58,194.5	$0.0	$0.0
Hydro	$484,669,838.3	$2,887,448.2	$104,804.6	$487,308,991.8	$6,771,463.1	$188,746.2	$2,639,153.5	$3,884,014.9	$83,941.6
Nuclear	$9,049,991,523.7	$0.0	$0.0	$9,129,040,875.8	$0.0	$0.0	$79,049,352.1	$0.0	$0.0
RICE Natural Gas	$14,189,947.6	$96,194.4	$0.0	$14,398,092.1	$277,466.1	$0.0	$208,144.5	$181,271.7	$0.0
RICE Oil	$1,457,402.1	$2,056.5	$104,177.5	$1,454,166.1	$5,956.4	$192,180.2	($3,236.0)	$3,899.9	$88,002.7
RICE Other	$53,295,887.4	$505,299.9	$57,816.4	$53,638,706.8	$999,598.8	$105,214.4	$342,819.4	$494,299.0	$47,398.0
Solar	$66,827,029.5	$0.0	$0.0	$66,845,393.9	$0.0	$0.0	$18,364.4	$0.0	$0.0
Steam Coal	$8,410,313,995.3	$5,163,185.9	$6,771.2	$8,489,007,895.6	$19,217,436.0	$32,253.0	$78,693,900.3	$14,054,250.1	$25,481.8
Steam Natural Gas	$271,573,014.0	$587,459.2	$0.0	$274,847,880.8	$1,847,087.4	$0.0	$3,274,866.7	$1,259,628.2	$0.0
Steam Oil	$40,052,929.0	$40,336.8	$0.0	$40,595,454.0	$136,886.7	$0.0	$542,525.1	$96,549.9	$0.0
Steam Other	$230,868,650.2	$226,751.1	$0.0	$232,480,068.2	$432,362.9	$0.0	$1,611,418.0	$205,611.8	$0.0
Wind	$611,688,031.0	$0.0	$0.0	$617,855,871.3	$0.0	$0.0	$6,167,840.3	$0.0	$0.0
Total	$27,943,196,368.3	$39,932,019.4	$6,775,087.1	$28,191,913,830.5	$113,720,359.2	$13,522,850.2	$248,717,462.2	$73,788,339.8	$6,747,763.1

Table 40 Generator revenues per ICAP MW by technology type: 2018, Case B to Case C 15 minute

	Revenue ($/MW)								
	Case B			Case C1			Difference		
	Generation	SR	PR	Generation	SR	PR	Generation	SR	PR
Battery	$3,719.16	$0.02	$0.00	$3,787.59	$7.64	$0.95	$68.43	$7.61	$0.95
CC	$161,695.31	$478.18	$0.01	$162,872.26	$1,336.60	$0.06	$1,176.95	$858.42	$0.05
CT Natural Gas	$35,493.90	$230.59	$80.00	$36,257.11	$651.28	$188.02	$763.21	$420.70	$108.01
CT Oil	$11,688.61	$426.46	$1,129.02	$11,807.29	$895.97	$2,081.60	$118.68	$469.51	$952.59
CT Other	$132,876.67	$269.50	$525.77	$134,007.51	$691.86	$997.64	$1,130.85	$422.36	$471.87
Fuel Cell	$248,992.51	$0.00	$0.00	$250,932.32	$0.00	$0.00	$1,939.82	$0.00	$0.00
Hydro	$60,032.93	$357.65	$12.98	$60,359.82	$838.74	$23.38	$326.89	$481.09	$10.40
Nuclear	$259,519.54	$0.00	$0.00	$261,786.38	$0.00	$0.00	$2,266.84	$0.00	$0.00
RICE Natural Gas	$117,856.71	$798.96	$0.00	$119,585.48	$2,304.54	$0.00	$1,728.77	$1,505.58	$0.00
RICE Oil	$6,344.81	$8.95	$453.54	$6,330.72	$25.93	$836.66	($14.09)	$16.98	$383.12
RICE Other	$147,642.22	$1,399.80	$160.17	$148,591.91	$2,769.13	$291.47	$949.69	$1,369.33	$131.30
Solar	$48,151.96	$0.00	$0.00	$48,165.20	$0.00	$0.00	$13.23	$0.00	$0.00
Steam Coal	$130,644.23	$80.20	$0.11	$131,866.65	$298.52	$0.50	$1,222.42	$218.32	$0.40
Steam Natural Gas	$27,083.90	$58.59	$0.00	$27,410.51	$184.21	$0.00	$326.60	$125.62	$0.00
Steam Oil	$17,459.86	$17.58	$0.00	$17,696.36	$59.67	$0.00	$236.50	$42.09	$0.00
Steam Other	$194,252.12	$190.79	$0.00	$195,607.97	$363.79	$0.00	$1,355.84	$173.00	$0.00
Wind	$67,824.41	$0.00	$0.00	$68,508.31	$0.00	$0.00	$683.89	$0.00	$0.00
Total	$133,665.02	$191.01	$32.41	$134,854.75	$543.98	$64.69	$1,189.73	$352.96	$32.28

To estimate the increase in carbon dioxide emissions due to the ORDC, the emissions rate for each technology, as calculated by the EIA, is multiplied by a generic heat rate for the technology and the simulated MWh of energy.[8] Table 41 provides the estimated increase in CO_2 emissions in short tons.

[8] Carbon Dioxide Emissions Coefficients, Energy Information Administration, <https://www.eia.gov/environment/emissions/co2_vol_mass.php>, accessed May 9, 2019.

Table 41 Estimated emissions increase: 2018, Case B to Case C 15 minutes

	CO2 Rate (lbs/MMBtu)	Heat Rate (MMBtu/MWh)	CO2 Rate (tons/MWh)	CO2 Case B (tons)	CO2 Case C 15 (tons)	CO2 Difference (tons)
Battery						
CC	117.00	7.5	0.44	99,811,925	99,674,572	(137,353)
CT Natural Gas	117.00	11.0	0.64	11,023,488	11,229,780	206,291
CT Oil	161.30	13.0	1.05	246,259	245,507	(752)
CT Other	117.00	11.0	0.64	106,222	106,210	(12)
Fuel Cell						
Hydro						
Nuclear						
RICE Natural Gas	117.00	11.0	0.64	205,511	208,057	2,546
RICE Oil	161.30	13.0	1.05	9,586	9,603	17
RICE Other	117.00	11.0	0.64	947,615	947,331	(284)
Solar						
Steam Coal	210.20	11.0	1.16	271,043,498	270,982,403	(61,095)
Steam Natural Gas	117.00	11.0	0.64	3,309,329	3,330,236	20,907
Steam Oil	161.30	11.0	0.89	287,795	288,846	1,050
Steam Other	117.00	11.0	0.64	4,074,738	4,073,092	(1,646)
Wind						
Total				386,991,227	387,022,544	31,317