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Monitoring Analytics

January 4, 2021

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *Chalk Point Power, LLC*, Docket No. ER21-573-000; *Dickerson Power, LLC*, Docket No. ER21-574-000; *Lanyard Power Marketing*, LLC, Docket No. ER21-575-000; *Morgantown Power, LLC*, Docket No. ER21-577-000; *Morgantown Station, LLC*, Docket No. ER21-578-000

Dear Ms. Bose:

On December 24, 2020, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submitted a protest in this proceeding. The initially filed version is missing a footnote and missing certain indicated attachments meant to be provided for convenience.

Specific changes include:

- Footnote 14 is added, the Attachment E indicated in footnote 14 is provided, and the subsequent footnotes are renumbered;
- Attachment A referenced in footnote 10, is redesignated Attachment C, and provided;
- Attachment B referenced in footnote 11 is redesignated Attachment D, and provided;
- Attachment C referenced in footnote 20, revised to be footnote 21, is redesignated Attachment F, and provided.

The pleading remains the same in all other respects. Attached please find a corrected version.

If you have any questions regarding this filing, please contact the undersigned at (610) 271-8053.

Sincerely,

Jeffrey W. Mayes, General Counsel

Attachment

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Chalk Point Power, LLC	)	Docket No. ER21-573-000
Dickerson Power, LLC	)	Docket No. ER21-574-000
Lanyard Power Marketing, LLC	)	Docket No. ER21-575-000
Morgantown Power, LLC	)	Docket No. ER21-577-000
Morgantown Station, LLC	)	Docket No. ER21-578-000
	)	

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] and Order Nos. 816 and 861,[2] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[3] submits this protest to the applications for market based rates authorization submitted by Chalk Point Power, LLC; Dickerson Power, LLC; Lanyard Power Marketing, LLC; Morgantown Power, LLC; Morgantown Station, LLC; all of which are wholly owned direct and indirect subsidiaries of

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1 18 CFR § 385.211 (2019).

2 *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, FERC Stats. & Regs. ¶ 31,374 (2015) ("Order No. 816"), *order on reh'g*, Order No 816-A, 155 FERC ¶ 61,188 (2016); *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, 168 FERC ¶ 61,040 at P 21 (July 18, 2019) ("Any objections to a Seller's market-based rate authority can and should occur as a direct response to an initial application, a change in status filing, a triennial update, or in a proceeding instituted under FPA section 206. The Commission will consider all relevant information in the record when determining whether the Seller can obtain or retain market-based rate authority. This will continue to occur notwithstanding the existence of Commission-approved monitoring and mitigation.") ("Order No. 861"); *order on reh'g*, Order No. 861-A, 170 FERC ¶ 61,106 (2020).

3 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").

GenOn Holdings, LLC, on December 4, 2020 ("Chalk Point Resources"), in this proceeding. The protest is limited to the extent that such market based rates authorization applies or may apply to sales of energy or capacity in PJM markets.

This proceeding concerns a new application for authorization to charge market based rates. Chalk Point Resources rely on effective PJM market power mitigation to address any market power that it may possess.[4] The current approach to market power mitigation is insufficient to support market based rate authorizations.

Unless and until the deficiencies in PJM's market power mitigation in the capacity market are corrected, the Commission should authorize participation in the PJM capacity market at market based rates only on the condition that market sellers offer their resources in the PJM capacity market at or below the competitive capacity offer, defined consistent with the mathematics of the PJM capacity performance design and the actual number of PAI. Currently, such offers are equal to the Avoidable Cost Rate adjusted for expected Capacity Performance penalties and bonuses.

Unless and until the deficiencies in PJM's market power mitigation in the energy market are corrected, the Commission should authorize participation in the PJM energy market at the competitive offer in the energy market, which is a cost-based offer in the PJM energy market with operating parameters that are at least as flexible as the defined unit specific parameter limits in the PJM energy market.

In the confidential Attachment A to this filing, the Market Monitor provides evidence that PJM market power mitigation is insufficient to ensure competitive market outcomes for its resources. Because the information in Attachment A is confidential and market sensitive, the Market Monitor also includes a proposed PJM Markets Protective Agreement in Attachment B for use in this proceeding. The proposed PJM Markets

4 Chalk Point Resources at 16.

Protective Order is substantially identical to the protective order relied upon in *Independent Market Monitor for PJM v. PJM Interconnection, L.L.C.*, Docket No. EL19-27-000.[5]

I. COMMENTS

A. Market Based Rates Authorization in PJM Depends on Market Power Mitigation.

Pursuant to Order No. 816 and Order No. 861, market sellers in PJM rely on the market power mitigation in the PJM Market Rules in asserting that their participation in the PJM markets at market based rates does not raise horizontal market power concerns.[6] Order No. 861 (at P 21) recognizes that an intervenor may challenge the presumption that market power mitigation is sufficient by presenting evidence, including that provided in the Market Monitors' reports. Such evidence is contained in the Market Monitor's State of the Market Reports for PJM and in the complaint filed by the Market Monitor regarding the capacity market seller offer cap.[7]

Order No. 861 also requires a demonstration by intervenors that sellers have market power in the relevant markets.[8] Order No. 861 recognizes that the intervenors may not

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5 Differences include (i) deletion of references to PJM, (ii) deletion of references to Non-Disclosure Certificates from a prior PJM Markets Protective Order; and (iii) addition of a provision allowing the Commission to resolve disputes when there is no Presiding Judge.

6 Order No. 861 at P 22 ("The public and the Commission will continue to have access to a Seller's ownership information, vertical market power analysis, asset appendix, and EQRs, as well as to the market monitors' reports. For example, PJM IMM notes that its quarterly State of the Market reports contain a comprehensive listing of market power concerns. Anyone may use this information in support of a challenge to a Seller's market-based rate authority. The Commission would then consider this and other information to determine whether the Seller may obtain or retain market-based rate authority. In addition, contrary to Public Citizen's argument that "once [market-based rate] authority is granted, [the Commission] is unlikely to take it away," the standard for obtaining and retaining market-based rate authority is the same. The Commission can and does institute FPA section 206 proceedings when potential market power concerns arise.").

7 *See* Docket No. EL19-47-000.

8 Order No. 861 at P 26.

provide indicative screens.[9] Analysis of PJM markets shows that all PJM sellers have the potential to have and exercise local market power at any time based on transmission constraints or reliability needs that may arise in any location in the PJM market for a variety of reasons. Without adequate market power mitigation, passing indicative market power screens does not provide customers protection from the effects of market power on prices. It serves no useful purpose for the Commission to request indicative screens. In this case, rather than indicative screens, the Market Monitor provides actual market power results from the PJM energy market. Actual market results are a better indication of structural market power than indicative screens. Even without demonstrating that market power exists based on historical market results, the Commission cannot be assured that market power is sufficiently mitigated unless PJM has effective market power mitigation that can be relied on in all future scenarios when market power may arise.

B. The PJM Capacity Market Is Not Competitive Due to Inadequate Market Power Mitigation.

The Market Monitor has provided ample evidence that the PJM capacity market is not competitive due to inadequate market power mitigation. The Market Monitor explained its findings regarding the Market Seller Offer Cap and provided evidence of noncompetitive behavior in its report analyzing the 2021/2022 RPM Base Residual Auction.[10] In its subsequent State of the Market Reports, the Market Monitor described the issues and found that the PJM capacity market is not competitive.[11] On February 21, 2019, the Market Monitor filed a complaint explaining that the Market Seller Offer Cap is

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9 *Id*. at P 27.

10 *See* Monitoring Analytics, LLC, *Analysis of the 2021/2022 RPM Base Residual Auction: Revised* (August 24, 2018), included as Attachment C.

11 *See* Monitoring Analytics, LLC, *2020 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity Market, included as Attachment D.

overstated, allowing market power to be exercised by some sellers.[12] [13] Based on the evidence provided, the Market Monitor rebuts the presumption that PJM's market power mitigation is adequate to support market based rates in the PJM capacity market.

C. The PJM Energy Market Results Are Competitive Overall, but Market Power Mitigation Is Inadequate in Many Circumstances.

The Market Monitor has provided ample evidence of the inadequacies of PJM energy market power mitigation in its State of the Market Reports.[14] Some sellers that fail the structural market power test, the Three Pivotal Supplier test ("TPS test"), are able to set prices with a substantial markup over their cost-based offer. Some sellers that fail the TPS test are able to operate, set prices, and collect uplift payments with operating parameters that are less flexible than their defined parameter limits. Based on the evidence provided, the Market Monitor rebuts the presumption that PJM market power mitigation is adequate to support market based rates in the PJM energy market.

D. Cost-based Offers and Parameter Limits Should Be Required Until Market Power Mitigation Is Adequate in PJM.

Based on the evidence provided by the Market Monitor, market based rate authorization for PJM market sellers in this proceeding should only permit offers in the PJM capacity market at or below the competitive capacity offer, defined consistent with the mathematics of the PJM capacity performance design and the actual number of PAI.[15] Currently, such offers are equal to the Avoidable Cost Rate adjusted for expected Capacity

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[12] Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

[13] Comments of the Independent Market Monitoring for PJM, Docket No. ER15-623 & EL15-29 (December 17, 2020).

[14] *See* Monitoring Analytics, LLC, *2020 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, included as Attachment E.

[15] The competitive offer should also be consistent with any minimum offer price rule approved by the Commission.

Performance penalties and bonuses.[16] Market based rate authorizations should permit only offers at or below the competitive offer in the energy market, which are cost-based offers in the PJM energy market with operating parameters that are at least as flexible as the defined unit specific parameter limits in the PJM energy market.[17] [18]

This approach is similar to the approach taken by the Commission in its 2016 authorization of market based rates for Arizona Public Service Co., where the Commission found the California ISO's market power mitigation insufficient to address market power concerns in the Energy Imbalance Market.[19] In that case, the Commission restricted participation to cost-based offers as defined in the tariff.[20]

Reliance on competitive, cost-based offers should be removed only when the application of market power mitigation in the PJM capacity market and the application of market power mitigation in the PJM energy market are modified consistent with the explicit recommendations of the Market Monitor.[21]

The Market Monitor recommends, in accordance with the applicable policies on market based rate authorizations, that the Commission institute "a separate section 206

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16 *See* Attachment A to the Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

17 *See* OA Schedule 2.

18 *See* OA Schedule 1 § 6.6.

19 *Arizona Public Service Co.*, 156 FERC ¶ 61,148 at P 26 (2016) ("[W]e authorize APS's participation in the EIM at market-based rates on the condition that it offer its units that are participating in the EIM at or below each unit's Default Energy Bid, as detailed below. Such a condition should reduce the potential adverse effects on the market should withholding occur."); *see also Nevada Power Company,* 153 FERC ¶ 61,206 (2015), *order on reh'g*, 155 FERC ¶ 61,186 (2016) (market-based rates authorization for EIM conditioned on seller offering their units that are participating in the EIM at or below each unit's Default Energy Bid").

20 *Id*. at P 39.

21 *See* Monitoring Analytics, LLC, *2020 Quarterly State of the Market Report for PJM: January through June*, Section 2: Recommendations, included as Attachment F.

proceeding to investigate whether the existing RTO/ISO mitigation continues to be just and reasonable."[22] Under this defined process, flaws in PJM's market power mitigation can be addressed and restrictions on individual market based rates authorizations can be lifted, consistent with the public interest.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this protest.

Respectfully submitted,

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Dated: December 24, 2020

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22 *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697-A, 123 FERC ¶ 61,055 at P 5 (April 21, 2008).

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 24th day of December, 2020.

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Attachment C

Analysis of the 2021/2022 RPM Base Residual Auction: Revised

The Independent Market Monitor for PJM

August 24, 2018

Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the fifteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2021/2022 Delivery Year) which was held from May 10 to 16, 2018, and responds to questions raised by PJM members and market observers about that auction. The MMU prepares a report for each RPM Base Residual Auction.

This report addresses, explains and quantifies the basic market outcomes. This report also addresses and quantifies the impact on market outcomes of: the ComEd LDA Capacity Emergency Transfer Limits (CETL); the PSEG LDA CETL; the forecast peak load; VRR curve definition; Demand Resources (DR) and Energy Efficiency (EE) resources; seasonal offers and seasonal matching; capacity imports; Price Responsive Demand (PRD); the EE add back mechanism; offers for nuclear resources; and noncompetitive offers by some generation resources.[1]

Conclusions and Recommendations

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. Local markets may have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The level of elasticity incorporated in the RPM demand curve, called the Variable Resource Requirement (VRR) curve, is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more

[1] The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules would mean that market participants would not be able to rely on the competitiveness of the market outcomes. However, the market power rules are not perfect and, as a result, competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. Issues with the definition of the offer caps in the 2021/2022 BRA resulted in noncompetitive offers and a noncompetitive outcome.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of a competitive offer was changed in the Capacity Performance rules that are now part of the PJM capacity market rules. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio and expected performance assessment intervals (PAI), the competitive, profit maximizing offer is (net CONE times B), where B is the expected average balancing ratio. This is the default offer cap for such units under defined assumptions.[2] Those assumptions include: there are expected PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI. Those assumptions were not correct for the 2021/2022 BRA and net CONE times B was not the correct offer cap as a result.

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2 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

The MMU verified the reasonableness of cost data and calculated the derived offer caps based on submitted data for resources that submitted unit specific data; calculated unit net revenues; verified that CP offer caps for low ACR units did not exceed net CONE times B; evaluated CP offer caps for high ACR units including any risk adders; reviewed Minimum Offer Price Rule (MOPR) unit specific exception requests; reviewed offers for Planned Generation Capacity Resources; verified capacity exports; verified offers based on opportunity costs; reviewed requests for exceptions to the RPM must offer requirement; reviewed requests for exceptions to the Capacity Performance (CP) must offer requirement; verified the sell offer Equivalent Demand Forced Outage Rates (EFORds); reviewed requests for alternate maximum EFORds; reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verified clearing prices based on the supply and demand (VRR) curves; and verified that the market structure tests were applied correctly.[3] All participants to whom the three pivotal supplier (TPS) test was applied (in the RTO, EMAAC, PSEG, ATSI, ComEd, and BGE RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[4] [5] The offer caps are designed to reflect the marginal cost of capacity but the offer cap did not reflect the marginal cost of capacity in this BRA.

Based on the data and this review, the MMU concludes that the results of the 2021/2022 RPM Base Residual Auction were not competitive as a result of economic withholding by resources that used offers that were consistent with the net CONE times B offer cap but not consistent with competitive offers based on the correctly calculated offer cap. An accurate default offer cap for the 2021/2022 BRA can be calculated using an updated estimate for the expected number of PAI. The current assumption of 360 intervals, or 30

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3 Attachment A reviews why the MMU calculation of clearing prices differs slightly from PJM's calculation of clearing prices and includes recommendations for improving the market clearing algorithm.

4 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

5 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

hours, that the net CONE times B offer cap is based on, is not aligned with the last three years of history of emergency actions in the PJM energy market, and does not reflect the observed capacity reserve margins. If the expected number of performance assessment intervals (H) is updated to a smaller number, say 60 intervals (5 hours) in line with the lower expectation of emergency events, using the tariff defined nonperformance charge rate of net CONE divided by 30, the default offer cap can be calculated as one-sixth of net CONE times B. If a resource's net ACR is greater than the updated offer cap, the competitive offer is net ACR, adjusted with any CP bonus payments or nonperformance charges.[6]

The result of not applying market power mitigation rules to generation resources that do not, absent mitigation, increase the market clearing price, would have no impact on the clearing prices but would affect seasonal make whole payments paid to seasonal offers. The result would be an exercise of market power as a result of a failure of the rules. The rules should be fixed to ensure that market power cannot be exercised in future auctions.

The Capacity Performance design addressed significant recommendations raised by the MMU in prior reports. These recommendations were included in the Capacity Performance design which will not be fully implemented until the June 1, 2020, start of the 2020/2021 Delivery Year. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the Capacity Market design be strengthened. The MMU had recommended that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the Capacity Market as generation resources. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources.

The 2.5 percent offset was implemented to permit DR to clear in Incremental Auctions (IAs). The 2.5 percent of demand was withheld in the BRA, and PJM attempted to procure that amount in the IAs for the relevant delivery year, net of any change in the

6 *See* Attachment B.

forecast peak load. It was not added to counter persistent forecast errors. Forecast errors should be addressed directly and explicitly for all PJM forecasts. It is essential that PJM use the same forecasts for capacity markets and for transmission planning to ensure the long term consistency of RTEP and RPM. To effectively use a lower forecast for capacity in RPM by reducing demand by an arbitrary 2.5 percent resulted in biasing the overall market results in favor of transmission rather than generation solutions to reliability issues. PJM's approach to the forecast issue in the 2019/2020 through 2021/2022 BRAs, by eliminating the 2.5 percent offset and by including the impact of EE, is a step forward but PJM must continue to improve the sophistication of its forecast methods.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. But pseudo ties still permit external balancing authorities to have control over the availability and dispatch of pseudo tied external capacity resources under some conditions. The external balancing authorities must decide whether the terms of pseudo tie agreements are consistent with their requirements. But when the reliability needs of external balancing authorities are not consistent with external units serving as complete substitutes for PJM internal capacity, pseudo ties are not adequate to permit the participation of external capacity resources in the PJM Capacity Market.

Pseudo ties do not establish deliverability to PJM load. External areas must perform deliverability analyses consistent with PJM criteria and external generation must also be deliverable to PJM load. Pseudo ties do not guarantee that a NERC tag will not be required. Pseudo ties are subject to NERC Tagging requirements unless the pseudo tie is included in regional congestion management procedures. Pseudo ties do not ensure that the associated firm flow entitlements (FFE) are assigned to the unit and to PJM. This could result in the inability to dispatch external capacity resources in the day-ahead market which, for example, limits flows on MISO transmission lines to PJM's FFEs. This could also result in the payment of additional congestion by PJM load to MISO resulting from real-time operations. FFEs should be assigned to PJM for external capacity resources.

The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market.

Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.

The MMU has recognized that the pseudo tie requirement is not enough to ensure the external units are full substitutes for internal capacity resources. The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability.

CETL is a critical parameter that has significant impacts on capacity market outcomes. PJM needs to significantly improve the clarity and transparency of its CETL calculations. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. CETL analysis has assumed the equivalent of capacity imports in the form of emergency transfers when there are no capacity imports and can be no capacity imports (e.g. from the NYISO). That assumption has had a significant impact on suppressing capacity market prices. CETL should be based on the ability to import capacity only where capacity exists and where capacity has a must offer requirement. Any other assumption overstates the amount of capacity supply and suppresses market prices. This conclusion applies to both nonfirm and firm imports.

The MMU recommends using the lower of the cost or price-based offer to calculate energy costs in the calculation of net revenues which are an offset in the calculation of unit specific capacity resource offer caps. This recommendation was rejected by FERC.[7] The FERC approved approach, used in the 2021/2022 BRA, effectively requires use of the higher of the cost or price-based offer except when the resource is mitigated in the energy market. The FERC approved approach requires use of the higher cost-based offer if the price based offer is less than fuel costs plus environmental costs, even if the cost-based offer is greater than fuel cost plus environmental costs, and requires the use of the cost-based offer when the resource is mitigated and the cost-based offer is lower than the price-based offer.[8] Under the FERC approach, when the price-based offer was less than the fuel cost plus environmental costs, the higher cost-based offer would be used and net revenues would be lower under the FERC approach than under the MMU approach. The FERC approach meant that capacity market offer caps that incorporated net revenues would have lower net revenues and would be greater than or equal to the offer caps calculated under the MMU approach.

The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types,

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7 See 155 FERC ¶ 61,281 (2016).

8 *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

including planned generation, demand resources and imports.[9] [10] All DR should be on the demand side of the market rather than on the supply side.

The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[11] [12] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling

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9 See Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000. (December 20, 2013).

10 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

11 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

12 See the *2017 State of the Market Report for PJM*, Vol. 2, Section 5, Capacity.

assumptions.[13] The MMU recommends that the MOPR rule be extended to existing units in a manner comparable to the application of the MOPR rule to new units.[14]

Capacity market sellers are allowed to offer up to 10 sell offer segments for a resource and, for annual resources, specify a minimum MW quantity for every segment. The capacity market rules do not require the segments to be aligned with the physical operating attributes of the underlying capacity resource. In a competitive capacity market, there is no valid economic reason for capacity market sellers to specify a minimum MW quantity greater than 0 MW (inflexible sell offer segment) when offering a resource in multiple segments. A valid economic argument could be made for specifying a minimum MW quantity greater than 0 MW if the resource were offered as a single segment, representing one unit. The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.

The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. For example, under the current structure, any capacity transfer between the Dominion LDA, which is modeled within the Rest of the RTO LDA, and the Pepco LDA needs to pass through MAAC and SWMAAC LDAs, although Dominion and Pepco regions are linked by several transmission lines.

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13 *See* 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of net CONE."); *see also*, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20-000 and ER11-2875-000(March 4, 2011).

14 Comments of the Independent Market Monitor for PJM, Docket No. EL18-169 (June 20, 2018).

Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints.

The nested structure also contributes to an important inefficiency in the clearing of resources. Under the existing nested structure, every resource is eligible to satisfy the reliability requirement of the LDA where the resource is located and also all the higher level parent LDAs to which it belongs. For instance, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, PSEG, EMAAC, MAAC and RTO. However, the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the requirement of a higher level LDA yields a larger consumer surplus than clearing that resource in a lower level LDA. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement, instead of clearing to satisfy PSEG North's requirement. As a result, the optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. As a result of this feature, the clearing process requires iteratively solving a series of optimization models to ensure that the requirements of child LDAs are satisfied before the requirements of parent LDAs.[15] With such iterative solving, the clearing process would produce implausible outcomes such as lower prices from a reduction in supply.

The MMU recommends improving the RPM solution method related to make whole payments.[16] The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.

The MMU recommends that Energy Efficiency Resources not be included on the supply side of the capacity market, because PJM's load forecasts now account for future Energy Efficiency Resources, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the

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15 For more details on the clearing process, see Attachment A.

16 For more details on these recommendations, see Attachment A.

implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

The RPM rules require that offer caps are applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the three pivotal supplier test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[17] Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can result in clearing seasonal sell offers with prices greater than the clearing price and making seasonal make whole payments based on those high prices. The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments.

The MMU recommends that when expected PAIs (H) and balancing ratio (B) are not the same as the assumed levels used to calculate the default market seller offer cap of net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for the competitive offer of a CP resource. The MMU recommends that if the H used to calculate the Nonperformance Charge Rate is not the same as the expected number of H, the offer cap be recalculated for each BRA using both values of H separately and the fundamental economic logic for the competitive offer of a CP resource. The MMU recommends that PJM either use the last three years of history or develop a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the NonpPerformance Charge Rate. The MMU recommends that PJM either use the last three years of history or develop a forward looking estimate for the Balancing Ratio (B) during PAIs to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions similar to the annual IRM study.

Results

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the auction. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. As shown in Table 10 and Table 11, the 160,795.3 MW of cleared and make whole generation and DR for the entire

[17] OATT Attachment DD § 6.5.

RTO, resulted in a reserve margin of 22.0 percent and a net excess of 8,190.3 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW.[18] [19] Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side resulted in a calculated reserve margin of 21.1 percent and a net excess of 7,431.8 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW. In the 2021/2022 BRA, the reserve margin calculation including EE Resources was lower than the reserve margin calculation excluding EE, because the cleared MW of EE on the supply side was less than the EE add back MW on the demand side.

Table 1 and Table 2 summarize the sensitivity analyses.

The increase in the ComEd CETL of 1,510.0 MW, or 37.2 percent, from the 2020/2021 level to the 2021/2022 level had a significant impact on the auction results. The results of the scenario show that the ComEd price for the 2021/2022 RPM Base Residual Auction was higher than it would have been if the CETL had remained at the lower 2020/2021 CETL value. This counter intuitive price impact was a result of the interaction of the supply offers and the demand curve. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,320,327,063, a decrease of $980,550,043, or 10.5 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for ComEd resulted in a 11.8 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been using the 2020/2021 CETL value for ComEd. (Scenario 1)

PJM introduced updates to the PJM RTEP and corrections to the CETL calculations in August 2017. The updates to the planning process stem from the termination of the ConEd Wheel Agreement. The updates included changes to the PJM NYISO PAR flows. The corrections were that PJM will no longer assume non-firm import capacity is available when determining the CETL values for MAAC, EMAAC, PSEG, and PSEG North. It was incorrect to assume that external capacity resources were available to meet the demand for capacity in the PJM Capacity Market because external capacity resources

18 The 22.0 percent reserve margin does not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

19 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

are required to have firm transmission and, as a result of the absence of firm transmission in the NYISO tariff, no capacity resources have been or could be imported from NYISO. In clearing the PJM Capacity Market, the only relevant supply consists of capacity that meet the definition of capacity resources. The fact that external resources may be able to help PJM in an emergency, while potentially relevant from a planning perspective, is not relevant to defining the supply and demand of capacity resources in the PJM Capacity Market.

PJM included power flows associated with capacity imports and exports secured with firm transmission from neighboring regions in calculating CETL values between LDAs. To approximate the impact of power flows associated with imports from New York ISO, a sensitivity with a 200.0 MW reduction in the CETL value for PSEG LDA was used.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the PSEG CETL value had been 200 MW lower than the PSEG CETL value used for the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,306,030,179, an increase of $5,153,073, or 0.1 percent, compared to the actual results. From another perspective, the PSEG CETL value used for the 2021/2022 RPM Base Residual Auction resulted in a 0.1 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the PSEG CETL value been 200 MW lower. (Scenario 2)

The accuracy of the peak load forecast has a significant impact on RPM Base Residual Auction results. An analysis of the RPM auctions for the 2014/2015 through 2018/2019 delivery years shows that the peak load forecast for the Third Incremental Auction has been on average 5.8 percent lower than the peak load forecast for the corresponding Base Residual Auction. If the peak load forecast for the 2021/2022 RPM Base Residual Auction had been 5.8 percent lower and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $6,510,513,224, a decrease of $2,790,363,882, or 30.0 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2021/2022 Base Residual Auction resulted in a 42.9 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 5.8 percent below the PJM peak load forecast. (Scenario 3)

PJM adjusted the VRR curve to offset certain low probability risks by shifting the VRR one percent to the right, thereby increasing demand. The shift was recommended by the Brattle Group to lower the probability of under procuring capacity in the event of a supply or demand shock, or underestimating net CONE.[20] Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If a one percent rightward shift in the VRR curve had not been included in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,648,601,896, a decrease of $652,275,210, or 7.0 percent, compared to the actual results. From another perspective, shifting the VRR curve one percent to the right for the 2021/2022 RPM Base Residual Auction resulted in a 7.5 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been had the VRR curve not been shifted to the right by one percent. (Scenario 4)

The inclusion of all sell offers for Demand Resources and Energy Efficiency resources, including annual and seasonal, had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,030,339,776, an increase of $1,729,462,670, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 15.7 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources. (Scenario 5)

The 2021/2022 RPM Base Residual Auction was the third BRA held using the EE add back mechanism. RPM rules allow Energy Efficiency Resources to participate on the supply side. An adjustment is made to the demand curve through the EE add back mechanism to avoid double counting, since EE for the delivery year is reflected in the revised load forecast model for the same delivery year. The EE add back mechanism had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base

[20] "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, P. 68. The report is available at this link <http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en>.

Residual Auction would have been $8,450,275,422, a decrease of $850,601,684, or 9.1 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resource offers and the EE add back MW, resulted in a 10.1 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE Resources did not participate on the supply side. (Scenario 6)

The inclusion of sell offers for Annual Demand Resources and Annual Energy Efficiency resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,048,633,706, an increase of $1,747,756,600, or 18.8 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Annual Energy Efficiency Resources resulted in a 15.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Annual Energy Efficiency resources. (Scenario 7)

The level of DR products that buy out of their positions after the BRA suggests that the impact of DR on generation investment incentives needs to be carefully considered and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[21] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other capacity resources available in Incremental Auctions. This would suppress the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules governing the BRA.

The inclusion of sell offers for Seasonal Demand Resources and Seasonal Energy Efficiency resources had a small impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and

21 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017" <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,207,711,533, a decrease of $93,165,573, or 1.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Seasonal Energy Efficiency resources resulted in a 1.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Seasonal Energy Efficiency resources. (Scenario 8)

The results show that the inclusion of additional Seasonal Demand Resources and Seasonal Energy Efficiency resources caused price increases in some LDAs. One factor leading to this result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

The 2021/2022 RPM Base Residual Auction was the second BRA held using the Seasonal products for summer and winter capacity. The inclusion of seasonal offers (Demand Resources, Energy Efficiency Resources, and Generation Resources) had a limited impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers for Seasonal products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,296,441,218, a decrease of $4,435,888, or 0.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal offers resulted in a 0.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal offers. (Scenario 9)

The results show that the inclusion of seasonal offers caused price increases in some LDAs. One factor leading to this result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

The inclusion of sell offers from Demand Resources, Energy Efficiency resources, and Seasonal resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been

$11,031,353,576, an increase of $1,730,476,470, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources, Energy Efficiency resources, and Seasonal resources resulted in a 15.7 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, or Seasonal resources. (Scenario 10)

The inclusion of winter resources had a limited impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the amount of winter offers had been reduced by 50 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,271,942,523, a decrease of $28,934,583, or 0.3 percent, compared to the actual results. From another perspective, the inclusion of all winter offers resulted in a 0.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers from winter resources had been reduced by 50 percent. Removing 50 percent of the winter resources from the available supply led to a lower clearing price in the ComEd LDA. (Scenario 11)

RPM rules allow for the matching of complementary Seasonal products across LDAs. An offer for summer capacity in PSEG can be matched with an offer for winter capacity in DEOK, and the two offers would receive the price corresponding to the lowest common parent LDA. In this example, the only common parent LDA of PSEG and DEOK is RTO and the combined offer would receive the RTO clearing price. Matching seasonal offers across LDAs did not have an impact on the 2021/2022 RPM Base Residual Auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, all LDA clearing prices and clearing amounts would have remained the same and total RPM market revenues would have remained the same at $9,300,877,106. In the 2021/2022 RPM Base Residual Auction, the proportion of low priced offers for summer in the rest of the RTO, the lowest common parent for all LDAs, substantially increased from the 2020/2021 RPM Base Residual Auction. Restricting the matching of complementary seasonal products to the LDA in which they are located deprives a resource that did not clear for a lower LDA such as PSEG to be matched with a complementary seasonal product in a higher LDA such as rest of the RTO. However, the availability of similarly lower priced offers located in the rest of RTO resulted in no difference in clearing quantities and prices when the seasonal matching was restricted to be within the same LDA where the both summer and winter resources were physically located. (Scenario 12)

The inclusion of capacity imports in the 2021/2022 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,589,433,567, an increase of $288,556,461, or 3.1 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 3.0 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation resources had been reduced by 25 percent. (Scenario 13)

If offers for external generation were reduced by 100 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $10,427,509,062, an increase of $1,126,631,956, or 12.1 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 10.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if no offers from external generation resources were included in the auction. (Scenario 13, Scenario 14, Scenario 15, Scenario 16)

The inclusion of sell offers from Demand Resources, Energy Efficiency resources, Seasonal resources, and imports had a significant combined impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no offers from Demand Resources, Energy Efficiency resources, or Seasonal resources, and imports had been reduced by 100 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,997,162,266, an increase of $2,696,285,160, or 29.0 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources, Energy Efficiency resources, and seasonal resources and including all offers for external generation resources resulted in a 22.5 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources, Energy Efficiency resources, seasonal resources, or external generation resources. (Scenario 17)

Under the EE add back MW rules, the demand curve was shifted by an amount greater than the quantity of cleared EE, and the clearing price was increased as a result of the implementation of the EE add back mechanism. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,797,549,143, a decrease of

$503,327,963, or 5.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW resulted in a 5.7 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA. (Scenario 18)

The 2021/2022 RPM Base Residual Auction was the second BRA that included submissions for Price Responsive Demand (PRD). The inclusion of PRD had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there had been no submissions from PRD providers in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,424,270,494, an increase of $123,393,388, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.3 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 19)

Nuclear offer behavior changed in the 2021/2022 RPM Base Residual Auction compared to prior auctions. More nuclear capacity was offered at higher sell offer prices and fewer nuclear MW cleared.[22] (See Table 21, Table 22, and Table 30) To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. It is not asserted that a $0 per MW-day sell offer is accurate for all nuclear resources. If all nuclear offers were replaced by $0 per MW-day in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $5,215,048,770, a decrease of $4,085,828,337, or 43.9 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 78.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day. (Scenario 20)

The MMU identified noncompetitive offers that had a significant impact on the 2021/2022 RPM Base Residual Auction results.

[22] See PJM. News Releases, May 23, 2018. <http://www.pjm.com/-/media/about-pjm/newsroom/2018-releases/20180523-rpm-results-2021-2022-news-release.ashx>.

Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The PJM tariff defines the balancing ratio (B) used in the default offer cap as the average of balancing ratios during the actual performance assessment intervals that occurred during the three calendar years preceding the auction.[23] PJM did not experience any performance assessment intervals during the three year period that preceded the 2021/2022 RPM Base Residual Auction and the balancing ratio calculation was not feasible. PJM resolved the balancing ratio issue by changing the tariff to state that the balancing ratio for the 2021/2022 RPM Base Residual Auction would equal the balancing ratio value used for the 2020/2021 RPM Base Residual Auction.[24] PJM did not propose any updates to the non-performance charge rate or the default offer cap definition of net CONE times B. In doing so, PJM continued to assume an expected 30 hours, or 360 intervals, of PAIs for the 2021/2022 delivery year. This assumption is not consistent with the last three years of history of emergency actions in the PJM energy market. The correct way to account for the lack of performance assessment intervals during the three year history would have been to recognize that this means that unit specific net ACR is the offer cap under the capacity performance construct. This would have been consistent with a market participant having an expectation of a very low number of performance assessment intervals. This would have been consistent with the competitive offer

[23] OATT Attachment DD § 6.4(a).

[24] *See* PJM. "Reliability Pricing Model Offer Cap Tariff Revision for 2018 Base Residual Auction", Docket No. ER18-262 (November 7, 2017).

calculation logic that PJM filed in response to a deficiency letter issued by the Commission in the Capacity Performance docket.[25]

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the identified noncompetitive offers had been capped at net ACR in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,070,050,631, a decrease of $1,230,826,475, or 13.2 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 15.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR. (Scenario 21)

Tables for Results Section

Table 1 Scenario summary of RPM revenue: 2021/2022 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$9,300,877,106	NA	NA
1	Decrease in the ComEd CETL	$8,320,327,063	$980,550,043	11.8%
2	PSEG CETL Adjustment	$9,306,030,179	($5,153,073)	(0.1%)
3	Reduce Load Forecast by 5.8 percent	$6,510,513,224	$2,790,363,882	42.9%
4	Inclusion of 1 percent VRR right shift	$8,648,601,896	$652,275,210	7.5%
5	Inclusion of DR/EE Offers	$11,030,339,776	($1,729,462,670)	(15.7%)
6	Inclusion of EE Offers and EE Add Back	$8,450,275,422	$850,601,684	10.1%
7	Inclusion of Annual DR/EE Offers	$11,048,633,706	($1,747,756,600)	(15.8%)
8	Inclusion of Seasonal DR/EE Offers	$9,207,711,533	$93,165,573	1.0%
9	Inclusion of Seasonal Products	$9,296,441,218	$4,435,888	0.0%
10	Inclusion of DR/EE and Seasonal Resources	$11,031,353,576	($1,730,476,470)	(15.7%)
11	Inclusion of 50 Percent of Offers from Winter Resources	$9,271,942,523	$28,934,583	0.3%
12	Inclusion of Seasonal Matching Across LDAs	$9,300,877,106	$0	0.0%
13	Inclusion of 25 Percent of Offers for External Generation	$9,589,433,567	($288,556,461)	(3.0%)
14	Inclusion of 50 Percent of Offers for External Generation	$9,994,522,907	($693,645,801)	(6.9%)
15	Inclusion of 75 Percent of Offers for External Generation	$10,350,916,800	($1,050,039,694)	(10.1%)
16	Inclusion of 100 Percent of Offers from External Generation	$10,427,509,062	($1,126,631,956)	(10.8%)
17	Inclusion of DR/EE, Seasonal Capacity and External Generation	$11,997,162,266	($2,696,285,160)	(22.5%)
18	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	$8,797,549,143	$503,327,963	5.7%
19	Inclusion of PRD	$9,424,270,494	($123,393,388)	(1.3%)
20	Impact of nonzero Nuclear Offers	$5,215,048,770	$4,085,828,337	78.3%
21	Impact of noncompetitive Offers	$8,070,050,631	$1,230,826,475	15.3%

[25] *See* PJM. "Response of PJM Interconnection, L.L.C. to Commission's March 31, 2015 Information Request", Docket No. ER15-623 (April 10, 2015).

Table 2 Scenario summary of cleared UCAP: 2021/2022 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	163,627.3	NA	NA
1	Decrease in the ComEd CETL	164,508.9	(881.6)	(0.5%)
2	PSEG CETL Adjustment	163,627.3	0.0	0.0%
3	Reduce Load Forecast by 5.8 percent	155,349.8	8,277.5	5.3%
4	Inclusion of 1 percent VRR right shift	162,646.5	980.8	0.6%
5	Inclusion of DR/EE Offers	158,125.4	5,501.9	3.5%
6	Inclusion of EE Offers and EE Add Back	160,125.8	3,501.5	2.2%
7	Inclusion of Annual DR/EE Offers	158,398.2	5,229.1	3.3%
8	Inclusion of Seasonal DR/EE Offers	163,222.5	404.8	0.2%
9	Inclusion of Seasonal Products	163,142.0	485.3	0.3%
10	Inclusion of DR/EE and Seasonal Resources	158,125.1	5,502.2	3.5%
11	Inclusion of 50 Percent of Offers from Winter Resources	163,584.9	42.4	0.0%
12	Inclusion of Seasonal Matching Across LDAs	163,627.3	0.0	0.0%
13	Inclusion of 25 Percent of Offers for External Generation	163,320.8	306.5	0.2%
14	Inclusion of 50 Percent of Offers for External Generation	162,954.3	673.0	0.4%
15	Inclusion of 75 Percent of Offers for External Generation	162,656.6	970.7	0.6%
16	Inclusion of 100 Percent of Offers from External Generation	162,571.1	1,056.2	0.6%
17	Inclusion of DR/EE, Seasonal Capacity and External Generation	157,509.1	6,118.2	3.9%
18	Impact of Adjusting the VRR Curve by EE Add Back Amount that Differs from Cleared EE	162,803.4	823.9	0.5%
19	Inclusion of PRD	164,099.0	(471.7)	(0.3%)
20	Impact of nonzero Nuclear Offers	165,844.3	(2,217.0)	(1.3%)
21	Impact of noncompetitive Offers	164,132.1	(504.8)	(0.3%)

Clearing Prices

Table 3 shows the clearing prices for Capacity Performance Resources in the 2021/2022 BRA by zone compared to the corresponding net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year. The clearing prices for CP Resources were less than net CONE times B for every Zone. The ratio of clearing price to net CONE times B exceeded 85 percent for two zones.

Table 3 Clearing prices and net CONE times B: 2021/2022 RPM Base Residual Auction

Zone	CP Weighted Average Clearing Price ($ per MW-day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	CP Clearing Price less Net CONE Times B ($ per MW-day)	CP Clearing Price to Net CONE Times B
AECO	$165.70	$310.57	0.79	$243.80	($78.10)	68.0%
AEP	$140.00	$297.97	0.79	$233.91	($93.91)	59.9%
AP	$140.27	$278.10	0.79	$218.31	($78.04)	64.3%
ATSI	$171.32	$288.79	0.79	$226.70	($55.38)	75.6%
BGE	$171.86	$229.94	0.79	$180.50	($8.64)	95.2%
ComEd	$195.55	$324.08	0.79	$254.40	($58.85)	76.9%
DAY	$140.00	$294.15	0.79	$230.91	($90.91)	60.6%
DEOK	$140.00	$294.38	0.79	$231.09	($91.09)	60.6%
DLCO	$140.00	$298.94	0.79	$234.67	($94.67)	59.7%
DPL	$165.58	$282.50	0.79	$221.76	($56.18)	74.7%
Dominion	$140.00	$298.26	0.79	$234.13	($94.13)	59.8%
EKPC	$140.00	$308.82	0.79	$242.42	($102.42)	57.8%
External	$140.00	$302.63	0.79	$237.56	($97.56)	58.9%
JCPL	$165.72	$276.92	0.79	$217.38	($51.66)	76.2%
Met-Ed	$140.00	$274.82	0.79	$215.73	($75.73)	64.9%
PECO	$165.72	$282.13	0.79	$221.47	($55.75)	74.8%
PENELEC	$140.00	$201.82	0.79	$158.43	($18.43)	88.4%
PPL	$140.06	$283.01	0.79	$222.16	($82.10)	63.0%
PSEG	$192.25	$311.13	0.79	$244.24	($51.99)	78.7%
Pepco	$140.00	$268.61	0.79	$210.86	($70.86)	66.4%
RECO	$165.15	$308.45	0.79	$242.13	($76.98)	68.2%

Market Changes

RPM Market Design Changes

Seasonal Capacity

Effective for the 2020/2021 and subsequent Delivery Years, the RPM market design incorporated seasonal capacity resources.[26] [27]

Summer period capacity performance resources may include summer period demand resources, summer period energy efficiency resources, capacity storage resources, intermittent resources, or environmentally limited resources that have an average expected energy output during the summer peak-hour periods consistently and measurable greater than its average expected energy output during winter peak hour periods.

Winter period capacity performance resources may include capacity storage resources, intermittent resources, and environmentally limited resources that have an average

[26] 158 FERC ¶ 62,220.

[27] See Comments of the Independent Market Monitor for PJM. Docket No. ER17-367-000. (December 8, 2016).

expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.

Related to the winter period capacity resources, generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limit resource is deemed deliverable by PJM for the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year. Winter seasonal resources have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. This additional available system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer. This additional capacity in winter is available not because the resources with CIRs cannot perform to their summer capability in winter; it is available because they are not needed to perform at their summer capability in the winter due to lower peak loads.

PJM's practice of giving away winter CIRs that exist because of other resources that paid for necessary network upgrades creates a cross subsidization of interconnection costs. The additional capacity revenues that the winter seasonal resources receive based on winter capacity commitments that require use of the system capability paid for by other resources, increases the cross subsidization even further. If PJM were to retain the seasonal capacity markets construct, the MMU recommends that PJM create a market mechanism to value and efficiently allocate CIRs.

Capacity market sellers are able to combine intermittent resources, capacity storage resources, demand resources, energy efficiency resources, or environmentally limited resources to create an aggregate resource modeled in the smallest common LDA. While commercial aggregation rules within the same LDA were effective with the 2018/2019 delivery year with the implementation of the capacity performance rules, the seasonal capacity rules allow aggregation across LDAs and also allow capacity market sellers to offer standalone summer or winter resources and allow the auction clearing optimization to match and clear equal quantities of summer and winter resources.

The summer period capacity resources and winter period capacity resources located within the same LDA are cleared in equal quantities to satisfy the resource requirement of the LDA in which they are both located. The seasonal resources that did not clear are moved up to the immediate parent LDA to be matched with the complementary seasonal resources located within the parent LDA. The matched seasonal offers located in different LDAs are cleared to satisfy the resource requirement of the lowest common parent LDA. However, under the PJM rules, seasonal resources are required to deliver during the performance assessment intervals in the LDA where they are physically located, even though they are not cleared to satisfy the reliability requirement of that LDA. Moreover the seasonal matching rules are likely to increase the make whole payments because the seasonal resources offered higher than the clearing price could clear the auction when paired with complementary seasonal resources from other LDAs.

Price Responsive Demand (PRD)

Although price responsive demand was implemented in the RPM market rules effective May 15, 2012, the 2020/2021 BRA was the first RPM auction in which price responsive demand participated.[28] The major differences between DR and PRD include the less stringent measurement and verification requirements for PRD and the ability for PRD to receive PRD credits for the entire delivery year as compared to a summer period DR receiving auction credits for part of the delivery year.

Energy Efficiency Resource Rules

Prior to the 2019/2020 Base Residual Auction, EE resources were incorporated on the supply side of the capacity market for four years, after which they were included in the PJM demand forecast and eliminated from the supply side in order to avoid double counting. The 2020/2021 Base Residual Auction was the second BRA for which EE was reflected in the revised load forecast model without a lag.[29] While it would have been logical to eliminate EE from the supply side as a result, an administrative add back mechanism was implemented instead. Effective December 17, 2015, an EE add back mechanism and related changes were implemented to accommodate EE Resource participation on the supply side.[30]

The mechanics of the EE add back mechanism are complex and do not appropriately adjust for the level of cleared EE resources. For each BRA, the reliability requirement of the RTO and each LDA is increased by the UCAP value of all EE Resources with accepted Measurement and Verification Plans for the auction. This increase is the EE add back amount. For the 2021/2022 BRA, this meant that the RTO VRR curve was shifted to the right by 3,912.9 MW. If the initial results of the BRA solution yield a ratio of EE add back MW to cleared EE MW which exceeds a predetermined threshold ratio, the EE add back MW are set equal to the cleared EE MW from the initial solution times

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28 137 FERC ¶ 61,204.

29 See PJM. “2016 Load Forecast Report,” <http://www.pjm.com/~/media/documents/reports/2016-load-report.ashx> (January 2016).

30 These rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

the threshold ratio, and the auction clearing is rerun a second and final time. The threshold ratio is equal to the historic three year average of cleared EE MW in all auctions for a given delivery year divided by the cleared EE MW in the BRA for that delivery year. For the 2021/2022 BRA, the ratio in the initial solution of 3,912.9/2,832.0=1.38167373 did not exceed the applicable threshold ratio of 1.606739475. The logic of the threshold is not clear and is not consistent with an appropriate clearing of the Base Residual Auction.

Capacity Performance

Capacity Products and Resource Constraints

Effective for the 2018/2019 and subsequent Delivery Years, the Extended Summer and Limited DR products are eliminated. For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM procured two product types, Capacity Performance and Base Capacity. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint, were established for each modeled LDA. These maximum quantities were set for reliability purpose to limit the quantity procured of the inferior products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Effective with the 2020/2021 Delivery Year, PJM procures a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[31]

Short-Term Resource Procurement Target

Effective for the 2018/2019 and subsequent Delivery Years, the Short Term Resource Procurement Target was eliminated. Under the prior rules, application of the Short-Term Resource Procurement Target meant that 2.5 percent of the reliability requirement was removed from the demand curve (VRR curve).

CP Must Offer Requirement

Effective for the 2018/2019 and subsequent Delivery Years, all Generation Capacity Resources are subject to the CP must offer requirement, with the exception of Intermittent Resources and Capacity Storage Resources which are categorically exempt from the CP must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas,

31 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 19.

run of river hydroelectric, and other renewable resources. Exceptions to the CP must offer requirement may be requested by demonstrating that the Generation Capacity Resource is physically incapable of satisfying the requirements of a CP Resource. In addition, PJM, considering advice and recommendation from the MMU, may reject eligibility of a resource to offer as CP.[32]

Offer Caps

Effective for the 2018/2019 and subsequent delivery years, the default offer cap for Capacity Performance Resources is the applicable zonal net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios (B) during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such delivery year.

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR). AFAE is available only for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance that are assumed by Capacity Performance Resources when they submit an offer.

For the 2021/2022 RPM Base Residual Auction, PJM used the same balancing ratio as the 2020/2021 RPM Base Residual Auction while PJM conducts a stakeholder process to modify the balancing ratio determination.[33] There were no performance assessment intervals or emergency events in 2015 through 2017, so the balancing ratio for 2021/2022 based on the previous tariff definition would have been zero, meaning that the net CONE times B offer cap would have been $0 per MW-day and offer caps would have defaulted to net ACR. This is because without performance assessment intervals, there is no opportunity to earn capacity bonus revenues for an energy only resource, and the resource would have to take on a capacity obligation and earn capacity revenues from the auction, to meet its avoidable costs net of any energy and ancillary service revenues. The competitive offer for such a resource, and the offer cap, would be its net ACR.

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32 OATT Attachment DD § 5.5A(a)(i)(B).

33 Docket No. ER18-262-000.

Coupled Offers

Effective for the 2018/2019 and 2019/2020 Delivery Years, Capacity Market Sellers may submit coupled offers for CP and Base Capacity for any resource that can qualify as a CP Resource. Prior to the 2018/2019 Delivery Year, the coupling option was available to only DR and EE Resources.

Effective for the 2018/2019 through 2019/2020 Delivery Years, submission of a coupled offer is required for a Capacity Performance Resource Sell Offer that exceeds the applicable net CONE times B.

UCAP Value of DR and EE

Prior to the 2018/2019 Delivery Year, the UCAP value of DR and EE was equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool Requirement (FPR). Effective for the 2018/2019 and subsequent Delivery Years, the UCAP value of DR and EE is no longer discounted by the DR Factor.

Variable Resource Requirement Curve Shape and Gross Cost of New Entry (CONE) Values

Effective for the 2018/2019 and subsequent Delivery Years, the VRR curve shape and the Gross Cost of New Entry (CONE) values were revised as part of the triennial review. Between review periods, the gross CONE values for delivery years subsequent to 2015/2016 are determined by escalating the base values using the most recent twelve month change in the Handy-Whitman Index.

External Generation Resources

For the 2017/2018 through the 2019/2020 delivery year, Capacity Import Limits (CILs) were established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[34] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

34 147 FERC ¶ 61,060 (2014).

An external generation resource offering as a CP resource must obtain an exception to the CIL, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter. One of the most important requirements for offering a CP capacity import is that it must be pseudo tied. This is a new requirement and consistent with an MMU recommendation. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible.

The MMU has recognized that the pseudo tie requirement is not enough to ensure the external units are full substitutes for internal capacity resources.

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that has previously cleared an RPM auction.[35] The rule changes include defining coordination with other Balancing Authorities when conducting pseudo tie studies, establishing an electrical distance requirement, establishing a market-to-market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo-tie, a model consistency requirement, the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM, the requirement for the capacity market seller to obtain long-term firm point-to-point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM, establishing an operationally deliverable standard, and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at sub-regional transmission organization granularity.

RPM Must Offer Requirement and Market Power Mitigation

The 2020/2021 RPM Base Residual Auction was the seventh BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[36] These changes included clarifying the applicability of the must-offer requirement and the circumstances under which exemptions from the

35 161 FERC ¶ 61,197 (2017).

36 134 FERC ¶ 61,065 (2011).

RPM must offer requirement would be allowed, revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and mitigation, treating a proposed increase in the capability of a Generation Capacity Resource in exactly the same way as a Planned Generation Capacity Resource for purposes of market power mitigation.

The 2020/2021 RPM Base Residual Auction was the fifth BRA conducted under the process related PJM Tariff revisions.[37] These revisions included defining additional deadlines and accelerating deadlines in advance of an auction related to exception processes for market seller offer caps, alternate maximum EFORds, MOPR, and the RPM must offer requirement.

Effective October 15, 2013, new and revised deadlines for requesting an exception to the RPM must offer requirement due to planned retirement were implemented.[38] The rationale for the earlier deadline is to allow new entrants adequate time to respond and enter the PJM generation interconnection queue in response to a planned retirement. Previously, the deadline for requesting an exception to the RPM must offer requirement based on the reason of retirement was 120 days prior to the auction. For the 2017/2018 BRA, a transition mechanism applied under which the deadline for requesting an exception to the RPM must offer requirement due to planned retirement was November 1, 2013. For all Base Residual Auctions for delivery years subsequent to 2017/2018, the deadline is September 1 prior to the auction. For the 2019/2020 BRA, a waiver to the deadline was granted, setting the deadline at October 1, 2015, because Capacity Market Sellers would need information on the results of the CP Transition Incremental Auctions posted on August 31, 2015, and September 9, 2015, in order to make an informed decision on retiring a resource.[39]

Effective with the 2017/2018 Delivery Year, external resources which request and are granted exceptions to the CIL are treated as existing for purposes of the RPM must offer requirement for the relevant and subsequent delivery years.

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37 Letter Order in FERC Docket No. ER13-149-000 (November 28, 2012).

38 145 FERC ¶ 61,035 (2013).

39 152 FERC ¶ 61,151 (2015).

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[40] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants, increasing the threshold value used in the screen to 90 percent for CC and CT plants, eliminating the net short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation.

The 2019/2020 RPM Base Residual Auction was the sixth BRA conducted under the revised MOPR and the third conducted under the subsequent FERC orders related to the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[41]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again as a result of a settlement among some parties that was approved by FERC.[42] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those resources that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

On July 7, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion that vacated FERC orders approving the then current MOPR.[43][44] In those orders,

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40 135 FERC ¶ 61,022 (2011).

41 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011), *order on compliance*, 139 FERC ¶ 61,011, *order on compliance*, 140 FERC ¶ 61,123.

42 143 FERC ¶ 61,090 (2013).

43 143 FERC ¶61,090, *reh'g denied*, 153 FERC ¶61,066.

FERC had accepted a PJM filing that revised the MOPR to include a self-supply exemption and a competitive entry exemption on condition that MOPR continue to include the ability for a participant to calculate a unit specific offer. Effective December 8, 2017, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[45]

ACR

The default Avoidable Cost Rate (ACR) escalation method which had been recommended by the MMU was approved and became effective on February 5, 2013, for the 2016/2017 and subsequent Delivery Years.[46] [47] [48]

The FERC Order also approved updates to the base default ACR values and consolidation of the ACR technology classifications, which were effective for the 2017/2018 and subsequent Delivery Years.

Effective with the 2020/2021 Delivery Year, the default ACR based offer caps are not an offer cap option.

Demand Resource Rules

Effective January 31, 2013, a third test for determining the Limited DR Reliability Target was implemented by PJM with the goal of limiting the probability of requiring an

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44 NRG Power Marketing, LLC v FERC, No. 15-1452 (2017).

45 161 FERC ¶ 61,252 (2017) ("Remand Order").

46 For more details on the default ACR calculation issue, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," pp. 6-9 <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

47 PJM Interconnection, L.L.C., Docket No. ER13-529-000 (December 7, 2012) at 19.

48 142 FERC ¶ 61,092 (2013).

interruption of longer than six hours, which is the maximum duration of an interruption for a Limited DR product.[49]

Effective for the 2014/2015 through the 2016/2017 Delivery Years, the RPM market design incorporated Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type.[50] Each DR product type is subject to a defined period of availability, a maximum number of interruptions, and a maximum duration of interruptions. The RPM rule changes related to DR product types also included the establishment of a maximum level of Limited DR and a maximum level of Extended Summer DR cleared in the auction, which were defined as a Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the PJM region as a whole and LDAs for which a separate VRR curve was established.[51] Annual Resources include generation resources, Annual DR, and EE.

The Minimum Resource Requirements were targets established by PJM to ensure that a sufficient amount of Annual Resources were procured in order to address reliability concerns with the Extended Summer and Limited DR products and to ensure that a sufficient amount of Annual Resources and Extended Summer Resources were procured in order to address reliability concerns with the Limited DR product. The reliability risk associated with relying on either the Extended Summer or Limited DR products results from the fact that reliability must be maintained in all 8,760 hours per year while these resources were required to respond for only a limited number of hours when needed for reliability. The Minimum Annual Resource Requirement is the minimum amount of capacity that PJM would seek to procure from Annual Resources in order to maintain reliability based on a PJM analysis of the probability of needing Limited DR resources.[52] The Minimum Extended Summer Resource Requirement is the minimum amount of capacity that PJM would seek to procure from Annual Resources and Extended Summer DR. In other words, there is a maximum level of Limited DR and a maximum level of Extended Summer DR that PJM would purchase to meet reliability requirements, because additional purchases of these products was not consistent with reliability based on a PJM analysis of the probability of needing Limited DR resources when they were

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49 143 FERC ¶ 61,076 (2013).

50 134 FERC ¶ 61,066 (2011).

51 The LDAs for which Minimum Resource Requirements are established was subsequently revised. See 135 FERC ¶ 61,102 (2011).

52 *See* PJM filing initiating FERC Docket No. ER13-486-000 (November 30, 2012).

not available. The maximum level of Limited and Extended Summer DR was the difference between the minimum level of Annual Resources and the VRR curve.

As part of the definition of the new DR products effective with the 2014/2015 Delivery Year, coupled DR sell offers were defined. Coupled DR sell offers were linked sell offers for a Demand Resource that was able to provide more than one of the three DR product types. For example, a DR offer based on a single facility could be offered as Annual, Extended Summer and Limited simultaneously in a coupled offer. Only Demand Resources of different product types could be coupled, and the Capacity Market Seller must have specified a sell offer price of at least $0.01 per MW-day more for the less limited DR product type within a coupled segment group.

PJM's auction clearing mechanism resulted in a higher price for Annual Resources if the MW of Annual Resources that would otherwise clear the auction, including all resources, were less than the Minimum Annual Resource Requirement that PJM requires for reliability. In that case the auction clearing mechanism selected Annual Resources that were more expensive than the clearing price that would have otherwise resulted in order to procure the defined Minimum Annual Resource Requirement. PJM's auction clearing mechanism also resulted in a higher price for Extended Summer Resources if the MW of Extended Summer Resources that would have otherwise cleared the auction were less than the Minimum Extended Summer Resource Requirement that PJM required for reliability. In that case the auction clearing mechanism selected Extended Summer Resources that were more expensive than the clearing price that would otherwise have resulted in order to procure the defined Minimum Extended Summer Resource Requirement.

This result is also described as procuring the Annual or Extended Summer Resources out of merit order because the minimum resource requirements are binding constraints. In cases where one or both of the minimum resource requirements bind, resources selected to meet the minimum requirements received a price adder to the system marginal price, in addition to any locational price adders needed to resolve locational constraints.

Effective January 31, 2012, the 2.5 percent holdback was not subtracted from the Minimum Annual and Extended Summer Resource Requirements. The first auction affected was the 2015/2016 BRA. The prior rule required that the Short-Term Resource Procurement Target, or 2.5 percent holdback, be subtracted from all product types including Annual, Extended Summer and Limited DR. Under the old rule, in the case where either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement were binding, the maximum amount of Limited DR would be procured in the Base Residual Auction, leaving none to be procured in Incremental Auctions for the relevant delivery year. Under the new rule, the entire 2.5 percent was subtracted from the amount of Limited DR procured in the BRA, assuming either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement is binding. For example in the 2015/2016 BRA, applying the Short-Term Resource Procurement Target reduced the amount of Limited DR procured by 4,069.4 MW, which is equal to 2.5 percent of 162,777.4, the demand adjusted for FRR.

Effective for the 2017/2018 Delivery Year, the Minimum Annual and Extended Summer Resource Requirements were replaced by Limited and Sub-Annual Resource Constraints.[53] The Limited Resource Constraint limited the quantity of Limited DR that can be procured, and the Sub-Annual Constraint limited the quantity of Limited DR and Extended Summer DR that could be procured. Under the prior rules, the quantity of Limited DR and Extended Summer DR were not capped, as intended, at a fixed MW level. Under the prior rules, if the Minimum Annual Resource Requirement constraint were binding, the Extended Summer and Limited DR products would fill in the balance of capacity needed to meet the VRR curve. The modifications to the rules for the 2017/2018 Delivery Year reduced the impact of Limited and Extended Summer DR on market outcomes compared to what the impact would have been without the rule changes.

Effective March 2, 2014, every DR provider must submit a DR Sell Offer Plan, consisting of a completed template document with certain required information and a DR Offer Certification Form, at least 15 business days prior to an RPM Auction.[54] The DR plan enhancements are meant to standardize the information requirements for offering planned DR, increase the likelihood that offers are based on physical assets and reduce the level of speculative offers. However, the DR plan enhancements did not go far enough to ensure that DR offers are based on physical assets at the time of the offer and therefore did not address the issue of speculative offers that are replaced in incremental auctions.

Effective for the 2018/2019 and subsequent Delivery Years, the Extended Summer and Limited DR products are eliminated. For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM procured two product types, Capacity Performance and Base Capacity. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, which replaced the Sub-Annual Resource Constraint and Limited Resource Constraint, were established for each modeled LDA. These maximum quantities were set for reliability purpose to limit the quantity procured of the inferior products, including Base Capacity

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53 146 FERC ¶ 61,052 (2014).

54 146 FERC ¶ 61,150 (2014).

Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Effective with the 2020/2021 and subsequent delivery years, PJM will procure a single capacity product, Capacity Performance.

Effective for the 2018/2019 and subsequent delivery years, the Short Term Resource Procurement Target was eliminated. Under the prior rules, application of the Short-Term Resource Procurement Target meant that 2.5 percent of the reliability requirement was removed from the demand curve (VRR curve).

Credit Limited Offers

Capacity Market Sellers must establish credit if offering any Planned Capacity Resource, Qualified Transmission Upgrade, or an external resource without firm transmission in an RPM Auction. Effective with the 2014/2015 and subsequent delivery years, the RPM market design also included the implementation of credit limited offers, which allow a Capacity Market Seller to specify a Maximum Post-Auction Credit Exposure (MPCE) in dollars for a planned resource using a non-coupled offer type. Capacity Market Sellers utilizing coupled sell offers cannot use the MPCE option. The intent of credit limited offers is to allow Capacity Market Sellers to better manage their credit requirement by specifying the maximum amount of credit they are willing to incur and to provide the service of determining the maximum cleared MW given the MPCE limit. The MPCE option permits participants to offer capacity when they could not otherwise offer capacity based on an uncertain RPM credit rate that could vary with clearing prices.

Under the rule incorporating the ability to set an MPCE, the RPM market clearing process must yield a solution where no resource's Post-Auction Credit Exposure (PCE) exceeds its MPCE for credit limited offers. The Post-Auction Credit Rate is a function of the resource clearing price. As a result, the RPM auction must be solved iteratively until no MPCE violations exist.

Effective with the 2012/2013 through 2019/2020 Delivery Years, the RPM credit rate prior to the posting of the BRA results for proposed capacity resources other than Capacity Performance Resources is equal to the number of days in the delivery year times the greater of $20 per MW-day or 30 percent of the LDA net Cost of New Entry, and the RPM credit rate after posting the BRA results is the number of days in the delivery year times the greater of $20 per MW-day or 20 percent of the LDA resource clearing price for the relevant product type. Effective for the 2018/2019 and subsequent delivery years, the RPM credit rate prior to the posting of the BRA results for proposed Capacity Performance Resources is equal to the number of days in the delivery year times the greater of $20 per MW-day or 50 percent of the LDA net Cost of New Entry, and the RPM credit rate after posting the BRA results is the number of days in the delivery year times the greater of $20 per MW-day, 20 percent of the LDA resource clearing price for the relevant product type, or the lesser of 50 percent of the LDA net Cost of New Entry or 150 percent of the LDA net Cost of New Entry minus the LDA CP clearing price.

Effective with the 2020/2021 Delivery Year, credit limited offers are not available as the post auction credit rate of Capacity Performance resources is not solely a function of the resource clearing price.

Other Changes Affecting Supply and Demand

On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), a final rule setting maximum achievable control technology (MACT) emissions standards for hazardous air pollutants (HAP) from coal and oil fired electric utility steam generating units, pursuant to section 112(d) of the Clean Air Act.[55] The rule required compliance by April 16, 2015, with the possibility of one year extensions being granted to individual generation owners.[56]

The state of New Jersey has separately addressed NO_X emissions on peak energy days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD.[57] The rule implemented performance standards effective on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

MMU Method

The MMU reviewed the following inputs to and results of the 2021/2022 RPM Base Residual Auction: [58]

- Unit Specific Offer Caps. Verified that the avoidable costs (ACR), including avoidable fuel availability expenses and risk adders, opportunity costs and net revenues used to calculate offer caps were reasonable and properly documented;

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55 *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

56 *Id*. at 9465.

57 N.J.A.C. § 7:27–19.

58 Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd) for generation resources and as ICAP times the Forecast Pool Requirement (FPR) for Demand Resources and Energy Efficiency Resources. The EFORd values in this report are the EFORd values used in the 2021/2022 RPM Base Residual Auction.

- Net Revenues. Calculated actual unit-specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2015 through 2017;[59]

- Minimum Offer Price Rule (MOPR). Reviewed requests for Unit-Specific Exceptions;

- Offers of Planned Generation Capacity Resources. Reviewed sell offers for Planned Generation Capacity Resources to determine if consistent with levels specified in Tariff;

- Exported Resources. Verified that Generation Capacity Resources exported from PJM had firm external contracts or made documented and reasonable opportunity cost offers;

- RPM Must Offer Requirement. Reviewed exceptions to the RPM must offer requirement;

- CP Must Offer Requirement. Reviewed exceptions to the CP must offer requirement;

- Maximum EFORd. Verified that the sell offer EFORd levels were less than or equal to the greater of the one-year EFORd or the five-year EFORd for the period ending September 30, 2017, or reviewed requests for alternate maximum EFORds;

- CP Eligibility. Reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility.

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves;[60]

- Market Structure Test. Verified that the market power test was properly defined using the TPS test, that offer caps were properly applied and that the TPS test results were accurate.

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59 Net revenue values for the 2021/2022 RPM BRA were calculated consistent with the FERC order effective at the time. *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016).

60 Attachment A reviews why the MMU calculation of auction outcomes differs slightly from PJM's calculation of auction outcomes.

Market Structure Tests

As shown in Table 4, all participants in the RTO, EMAAC, PSEG, ATSI, ComEd, and BGE RPM markets failed the TPS test.[61] The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller failed the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price. Not mitigating sell offers for generation resources that do not, absent mitigation, increase the market clearing price would have no impact on the clearing prices in the auction but would affect seasonal make whole payments paid to seasonal offers. The result would be an exercise of market power as a result of a failure of the rules. Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can result in clearing seasonal sell offers with prices greater than the clearing price and making seasonal make whole payments based on those high prices. The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments.

Market power mitigation was applied to the Capacity Performance sell offers of zero generation capacity resources in the 2021/2022 RPM Base Residual Auction. All offers were less than the tariff defined offer caps or not applying the tariff defined offer cap did not increase clearing prices. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment intervals, exceeds the competitive level.

In applying the three pivotal supplier market structure test, the relevant supply for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO clearing price resulting from offer capped offers for all supply.[62] The relevant supply for the constrained LDA markets includes the incremental supply from generation resources inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the clearing price for the constrained LDA resulting from offer-capped offers for all supply. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint and meet the VRR curve for the LDA.

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61 See the MMU *Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

62 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

Table 4 presents the results of the TPS test and the one pivotal supplier test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.[63]

Table 4 RSI results: 2021/2022 RPM Base Residual Auction[64]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data or provide notification of intent to use the net CONE times B offer cap to the MMU by 120 days prior to the 2021/2022 RPM Base Residual Auction.[65] Market power mitigation measures are applied to Existing Generation Capacity

63 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. The appropriate market definition to use for the one pivotal supplier test includes all offers with costs less than or equal to 1.05 times the clearing price. See the MMU *Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

64 The RSI shown is the lowest RSI in the market.

65 The deadline for data submission changed from two months prior to the auction to 120 days prior to the auction, effective December 17, 2012, by letter order in FERC Docket No. ER13-149-000 (November 28, 2012).

Resources such that the sell offer is set equal to the tariff defined offer cap when the Capacity Market Seller fails the market structure test for the auction, the submitted sell offer exceeds the tariff defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[66] For RPM Base Residual Auctions, for Base Capacity prior to the 2020/2021 Delivery Year, offer caps are defined as avoidable costs less PJM market revenues, or the opportunity costs associated with selling capacity outside the PJM market. For Capacity Performance Resources, offer caps as defined as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Intervals in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year unless avoidable costs exceed this level, or opportunity costs.

Table 5 shows the zonal net CONE times B offer caps for the 2020/2021 and 2021/2022 RPM Base Residual Auctions. In all zones, the net CONE times B offer cap values increased from the 2020/2021 RPM Base Residual Auction, mainly due to lower net revenues for the 2015 through 2017 time period.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the Delivery Year.[67] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges. Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[68]

Effective for the 2018/2019 and subsequent Delivery Years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity

66 OATT Attachment DD § 6.5.

67 OATT Attachment DD § 6.8 (b).

68 OATT Attachment DD § 6.8 (a).

Performance Quantifiable Risk (CPQR).[69] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to input a documented price available for a PJM generation resource in a market external to PJM net of transmission costs, subject to export limits. If the relevant RPM market clears at or above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price the Generation Capacity Resource does not clear in the RPM market and it is available to sell in the external market.

As shown in Table 6, 1,132 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Base Residual Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (0.7 percent) including five generation resources (0.4 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,132 generation resources offered as Capacity Performance, 953 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 11 Planned Generation Capacity Resources had uncapped offers, 31 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 129 generation resources were price takers.

The APIR statistics are not included in this report, because the number of participants does not meet the minimum requirement defined in PJM's confidentiality rules. The fact that so few resources requested unit specific offer caps is further evidence that the net CONE times B offer cap exceeds competitive offers.

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 7, of the 7,276.0 ICAP MW of MOPR Unit-

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69 151 FERC ¶ 61,208.

Specific Exception requests, requests for 4,344.0 ICAP MW were granted. Of the 301.8 MW offered for MOPR Screened Generation Resources, 127.6 MW cleared and 174.2 MW did not clear.

Tables for Offer Caps and Offer Floors

Table 5 Net CONE times B: 2020/2021 and 2021/2022 RPM Base Residual Auctions

	2020/2021					2021/2022					Change				
Zone	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)
AECO	$367.97	$87.64	$280.33	0.79	$220.06	$364.78	$54.20	$310.57	0.79	$243.80	($3.19)	($33.44)	$30.24	0.00	$23.74
AEP	$365.52	$103.48	$262.03	0.79	$205.69	$364.43	$66.46	$297.97	0.79	$233.91	($1.09)	($37.02)	$35.94	0.00	$28.22
AP	$365.52	$135.36	$230.15	0.79	$180.67	$364.43	$86.33	$278.10	0.79	$218.31	($1.09)	($49.03)	$47.95	0.00	$37.64
ATSI	$365.52	$121.55	$243.96	0.79	$191.51	$364.43	$75.64	$288.79	0.79	$226.70	($1.09)	($45.92)	$44.83	0.00	$35.19
BGE	$374.61	$208.03	$166.58	0.79	$130.77	$386.17	$156.23	$229.94	0.79	$180.50	$11.56	($51.80)	$63.36	0.00	$49.73
ComEd	$365.52	$57.44	$308.07	0.79	$241.83	$364.43	$40.35	$324.08	0.79	$254.40	($1.09)	($17.10)	$16.01	0.00	$12.57
DAY	$365.52	$110.37	$255.14	0.79	$200.28	$364.43	$70.27	$294.15	0.79	$230.91	($1.09)	($40.10)	$39.01	0.00	$30.63
DEOK	$365.52	$101.67	$263.85	0.79	$207.12	$364.43	$70.05	$294.38	0.79	$231.09	($1.09)	($31.62)	$30.53	0.00	$23.97
DLCO	$365.52	$98.56	$266.96	0.79	$209.56	$364.43	$65.49	$298.94	0.79	$234.67	($1.09)	($33.07)	$31.98	0.00	$25.11
DPL	$367.97	$129.80	$238.17	0.79	$186.96	$364.78	$82.28	$282.50	0.79	$221.76	($3.19)	($47.52)	$44.33	0.00	$34.80
Dominion	$365.52	$88.29	$277.23	0.79	$217.63	$364.43	$66.16	$298.26	0.79	$234.13	($1.09)	($22.12)	$21.03	0.00	$16.50
EKPC	$365.52	$89.03	$276.49	0.79	$217.04	$364.43	$55.61	$308.82	0.79	$242.42	($1.09)	($33.42)	$32.33	0.00	$25.38
External	$368.44	$94.80	$273.64	0.79	$214.81	$370.71	$68.08	$302.63	0.79	$237.56	$2.27	($26.71)	$28.99	0.00	$22.75
JCPL	$367.97	$123.24	$244.73	0.79	$192.11	$364.78	$87.85	$276.92	0.79	$217.38	($3.19)	($35.39)	$32.19	0.00	$25.27
Met-Ed	$365.66	$117.20	$248.45	0.79	$195.03	$367.46	$92.64	$274.82	0.79	$215.73	$1.81	($24.56)	$26.37	0.00	$20.70
PECO	$367.97	$113.53	$254.44	0.79	$199.74	$364.78	$82.65	$282.13	0.79	$221.47	($3.19)	($30.88)	$27.69	0.00	$21.73
PENELEC	$365.66	$235.26	$130.40	0.79	$102.36	$367.46	$165.64	$201.82	0.79	$158.43	$1.81	($69.62)	$71.42	0.00	$56.07
PPL	$365.66	$115.95	$249.71	0.79	$196.02	$367.46	$84.45	$283.01	0.79	$222.16	$1.81	($31.49)	$33.30	0.00	$26.14
PSEG	$367.97	$81.28	$286.69	0.79	$225.05	$364.78	$53.64	$311.13	0.79	$244.24	($3.19)	($27.64)	$24.44	0.00	$19.19
Pepco	$374.61	$163.01	$211.60	0.79	$166.11	$386.17	$117.56	$268.61	0.79	$210.86	$11.56	($45.44)	$57.01	0.00	$44.75
RECO	$367.97	$85.67	$282.30	0.79	$221.61	$364.78	$56.32	$308.45	0.79	$242.13	($3.19)	($29.35)	$26.15	0.00	$20.52

Table 6 ACR statistics: 2021/2022 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	3	0.3%
Unit specific ACR (APIR and CPQR)	5	0.4%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	953	84.2%
Uncapped planned uprates and default ACR	NA	NA
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	31	2.7%
Uncapped planned uprates and price taker	0	0.0%
Uncapped planned generation resources	11	1.0%
Existing generation resources as price takers	129	11.4%
Total Generation Capacity Resources offered	1,132	100.0%

Table 7 MOPR statistics: 2021/2022 RPM Base Residual Auction

	Number of Requests (Company-Plant Level)	ICAP (MW) Requested	ICAP (MW) Granted	ICAP (MW) Offered	UCAP (MW) Offered	UCAP (MW) Cleared
Unit-Specific Exception for resources	8	6,605.0	3,673.0	0.0	0.0	0.0
Unit-Specific Exception for uprates	15	671.0	671.0	131.3	127.6	127.6
Other MOPR Screened Generation Resources	0	0.0	0.0	177.5	174.2	0.0
Total	23	7,276.0	4,344.0	308.8	301.8	127.6

Competitive Capacity Performance Offers

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR); and the resource's performance during performance assessment intervals (A) in the delivery year. [70]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables during the delivery year: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). This is because in the Capacity Performance pay for performance capacity model, the total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or charges forfeited) during the delivery year when the resources are required to perform. The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[71]

Attachment B explains the derivation of the competitive offer of a Capacity Performance resource. The competitive offer of a resource is the larger of the opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap that is based on its net ACR. The default offer cap is based on the opportunity cost of taking on a CP obligation when the resource could have earned enough revenues by staying as an energy only resource and earned enough bonus revenues to cover its avoidable costs. If the resource's avoidable costs are higher than what it expects to earn as bonuses during performance assessment intervals in the delivery year, its competitive offer is its net ACR adjusted with any bonuses or nonperformance charges it may incur during the delivery year. The default offer cap defined in the PJM tariff, net CONE times the average Balancing Ratio, is based on a number of assumptions:

70 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

71 OATT Attachment DD § 10A (d).

1. The net ACR of a resource is less than its expected energy only bonuses[72]:

$$\mathrm{ACR} \leq \frac{1}{12} \times \sum_{i=1}^{H} (\mathrm{CPBR}_i \times A_i)$$

$$\text{or ACR} \leq \frac{(\mathrm{CPBR} \times H \times \bar{A})}{12}$$

2. The expected number of performance assessment intervals equals360. (H = 30 hours times 12 intervals per hour)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment intervals ($\bar{A}$)

If the expectations of a market seller on any of these variables are different from the stated assumptions, the competitive offer of such a resource is different from net CONE times B. The recent history of a very low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design and the reduction in pool wide outage rates because of new units in the system and retirements of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[73] [74] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported.

The competitive offer calculation of a market seller whose assumptions are different from the assumptions used in the current default offer cap is illustrated in an example.

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72 H is the expected number of performance intervals in a delivery year and CPBR is the bonus payment rate in $ per MWh. The conversion factor of 12 is the number of five minute intervals in each hour.

73 PJM experienced zero emergency events since April 2014, that would have triggered a PAI in an area that at least encompasses a PJM transmission zone. See "Balancing Ratio Determination Issue", at 12 <http://www.pjm.com/-/media/committees-groups/committees/mic/20180404/20180404-item-10b1-balancing-ratio-determination-solution-options.ashx> (April 4, 2018).

74 See *2018 Quarterly State of the Market Report for PJM: January through June*, Vol. 2, Section 5, Capacity, Table 5-7.

The example uses the net CONE and average balancing ratio value used for the default offer cap published by PJM for the 2021/2022 BRA.[75]

Example Competitive Offer Calculation

Consider two resources in the AEP Zone with different avoidable costs, but otherwise similar assumptions:

- Resource X with a net ACR of $50,000 per ICAP MW per year, or $136.99 per ICAP MW per day.
- Resource Y with a net ACR of $10,000 per ICAP MW per year, or $27.40 per ICAP MW per day.
- Expected average performance ($\bar{A}$) of 75 percent during performance assessment intervals.
- Expected number of performance assessment intervals, H, is 60 (5 hours).
- Expected average balancing ratio ($\bar{B}$) during performance assessment intervals is 78.5 percent.
- Expectation that 20 percent of underperformance MWh are excused on average (in other words, bonus performance payment rate is equal to 80 percent of the nonperformance charge rate).

Resource X

Without a capacity commitment, resource X would have earned bonus payments during all the performance assessment intervals for its entire performance.

Energy only bonus revenues = $(\mathrm{CPBR} \times \mathrm{H} \times \bar{\mathrm{A}})/12$

Using a bonus performance rate of 0.8 times the nonperformance charge rate for the AEP zone, CPBR ($ per MWh) = $3,625.30 × 0.8 = $2,900.24 per MWh

Energy only bonus revenues = 2,900.24 ($/MWh) × 60 (intervals/year) × 0.75 /12 (intervals per hour)

= $10,875.90 per MW–year

[75] *See* PJM. "Final CP Market Seller Offer Cap Values," <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-final-cp-market-seller-offer-cap-values.ashx?la=en>.

The net ACR of the resource ($50,000 per MW-year) is greater than its expected energy only bonus revenues ($10,875.90 per MW-year). This is primarily because the lower number of performance assessment intervals creates fewer opportunities to earn bonuses. We refer to such resources as a 'High ACR' resource. The competitive offer of such a resource is:

$$\mathrm{p = ACR + PPR \times H \times (\overline{B} - \overline{A})/12}$$

In other words, the competitive offer is the sum of the resource's avoidable costs (ACR) plus any additional nonperformance charges it may incur due to nonperformance in the energy market during PAIs in the delivery year ($\mathrm{PPR \times H \times (\overline{B} - \overline{A})/12}$). This is because its expected average performance at 75 percent is less than the expected average balancing ratio of 78.5 percent. The competitive offer is calculated as:

$$\mathrm{p = \$50{,}000 + \$\,3{,}625.30 \times 60 \times (0.785 - 0.75)/12}$$

p = $50,634.43 per MW-year or $138.72 per MW-day

Resource Y

Without a capacity commitment, resource Y would have earned bonus payments during all the performance assessment intervals for its entire performance.

Energy only bonus revenues = $\mathrm{(CPBR \times H \times \overline{A})/12}$

Using a bonus performance rate of 0.8 times the nonperformance charge rate for the AEP zone, CPBR ($ per MWh) = $3,625.30 × 0.8 = $2,900.24 per MWh

Energy only bonus revenues = 2,900.24 ($/MWh) × 60 (intervals/year) × 0.75 /12 (intervals per hour)

= $10,875.90 per MW–year

The net ACR of the resource ($10,000 per MW-year) is lower than its expected energy only bonus revenues ($10,875.90 per MW-year). We refer to such resources as a 'Low ACR' resource. For such a resource to take on a capacity performance obligation, the minimum offer is the opportunity cost of doing so instead of staying on as an energy only resource. The competitive offer of such a resource is:

$$\mathrm{p = \ (CPBR \times H \times \overline{A})/12 + (PPR \times H \times (\overline{B} - \overline{A}))/12}$$

In other words, the competitive offer is the sum of the bonus revenues it would have earned as an energy only resource ($\mathrm{(CPBR \times H \times \overline{A})/12}$) plus any additional nonperformance charges it expects to pay as a CP resource ($\mathrm{(PPR \times H \times (\overline{B} - \overline{A}))/12}$).

This is because its expected average performance at 75 percent is less than the expected average balancing ratio of 78.5 percent. The competitive offer is calculated as:

$$p = (\$2{,}900.24 \times 60 \times 0.75)/12 + (\$3{,}625.30 \times 60 \times (0.785 - 0.75))/12$$

p = $11,510.33 per MW-year or $31.54 per MW-day

In comparison, the current default offer cap for the AEP zone, net CONE times B is:

Default offer cap = $85,375 per MW-year or $233.91 per MW-day

This example illustrates how, when a market seller's expectation on two variables is different from the assumptions used in the default offer cap calculation (in this case the bonus payment rate is estimated as 80 percent of the nonperformance charge rate, and the expected number of performance assessment intervals is 60), the competitive offers of resources across a range of avoidable costs are lower than the current default offer cap. This means that the default offer cap overstates the competitive offer for most resources. These resources are permitted to use the higher default offer cap rather than the competitive offer. This also illustrates that a resource subject to MOPR could support an offer less than the default offer cap.

As illustrated in the example, a market seller can similarly have different expectations for the other variables in the competitive offer calculation: resource availability (A) and balancing ratio (B). These expectations can lead to competitive offers below net CONE times B, the default offer cap. The observed offers below the default offer cap indicate that market sellers of Capacity Performance resources in PJM have different expectations than are assumed in the derivation of net CONE times B: (i) the number of performance assessment intervals (H) will be less than 360; (ii) the expected average performance of resources (A) will increase under the Capacity Performance framework, and; (iii) locational events where balancing ratio (B) is expected to be different from the historical average of 78.5 percent that PJM used for the default offer cap calculation.

Bonus Performance Payment Rate Dilution

An important consideration in a competitive offer calculation is the expectation about the capacity bonus performance payments. If market sellers expect that PJM will excuse resources that underperform, it leads to dilution of the bonus performance rate, compared to the nonperformance charge rate. Another reason for dilution of bonus performance payments is retroactive replacement transactions. Current market rules allow capacity resources that underperform, with certain restrictions on ownership and location, to enter into retroactive replacement transactions with resources that may have over performed during a performance assessment interval. Such a transaction allows the underperforming resource to avoid paying nonperformance charges by adjusting its expected performance after a performance assessment interval. Such a provision leads to fewer nonperformance charges collected and consequently, fewer bonus performance payments.

Dilution of bonus performance generally leads to lower competitive offers, since the opportunity of earning bonuses as an energy only resource decreases with a lower bonus performance payment rate. Offers and clearing prices in the capacity market reflect market sellers' expectations about PJM's implementation of the Capacity Performance design. The Capacity Performance design only works as intended if PJM actually implements the no excuses approach ordered by the Commission and ensures that resources can only meet their obligation and avoid penalties by actually performing during the most critical times.

Generation Capacity Resource Changes

As shown in Table 5, Capacity Performance offers were submitted for 1,132 generation resources in the 2021/2022 RPM Base Residual Auction, compared to 1,114 generation resources offered in the 2020/2021 RPM Base Residual Auction, a net increase of 18 generation resources. This was a result of 40 additional generation resources offered offset by 22 fewer generation resources offered.

The 40 additional generation resources offered consisted of 17 new resources (325.5 MW), 16 resources that were unoffered in the 2020/2021 BRA (370.8 MW), and seven resources that were previously entirely FRR committed (72.2 MW).[76]

The 17 new Generation Capacity Resources consisted of 12 solar resources (237.8 MW), three wind resources (65.7 MW), and three additional resources (22.0 MW). [77]

The 22 fewer generation resources offered consisted of nine deactivated resources (436.5 MW), five external resources not offered (610.3 MW), three intermittent resources not offered (5.3 MW), two Planned Generation Capacity Resources not offered (160.4 MW), two fewer resources resulting from aggregation of RPM resources, and one additional resource fully committed to FRR (23.2 MW). Table 8 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2020/2021 BRA and the 2021/2022 BRA.

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76 Unless otherwise specified, all volumes and prices are in terms of UCAP.

77 Some numbers not reported as a result of PJM confidentiality rules.

Table 8 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
HARRISBURG 4	PPL	14.0	19-Aug-16	17-Nov-16
ROANOKE VALLEY 1	RTO	165.0	01-Dec-16	01-Mar-17
ROANOKE VALLEY 2	RTO	44.0	01-Dec-16	01-Mar-17
SPRUANCE 1 RICH 1-2	RTO	115.5	18-Apr-17	12-Jan-19
COLVER NUG	MAAC	110.0	22-Nov-17	01-Sep-20
BRUNNER ISLAND DIESELS	PPL	7.5	27-Nov-17	25-Feb-18
DIXON LEE LF	ComEd	3.6	06-Dec-17	10-Jan-18
EVERGREEN	MAAC	25.0	02-Feb-18	01-May-18
MORRIS COGEN	ComEd	1.9	16-Feb-18	31-May-18

RTO Market Results

Total Offers

Table 9 shows total RTO offer data for the 2021/2022 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[78] [79] As shown in Table 14, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, increased 3,962.0 MW (2.0 percent) from 200,728.4 MW in the 2020/2021 RPM BRA to 204,690.4 MW.

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The net internal capacity change attributable to capacity modifications can be determined by holding the EFORd level constant at the prior auction's level. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications. As shown in Table 14, the 3,962.0 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (2,467.0 MW), net DR capacity changes (1,055.9 MW), net EE modifications (594.4 MW), the EFORd effect due to higher sell offer EFORds (-164.6 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (9.3 MW).[80]

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78 Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. For example, MAAC and ATSI are nested in the RTO.

79 Maps of the LDAs can be found in the *2016 State of the Market Report for PJM*, Appendix A, "PJM Geography."

80 Prior to the 2018/2019 Delivery Year, the UCAP value of a load management product is equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool

As shown in Table 16, total internal RTO unforced winter capacity for November through April increased 253.1 MW from 825.2 MW in the 2020/2021 BRA to 1,078.3 MW in the 2021/2022 BRA. The 253.1 MW increase in winter capacity was a result of net generation winter capacity modifications (253.1 MW).

The net generation capacity modifications reflect new and reactivated generation, deactivations, and cap mods to existing generation. Total internal RTO unforced capacity includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources for the 2021/2022 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[81] The ICAP of a unit may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[82] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity modifications, DR plan changes, and EE plan changes were the result of owner reevaluation of the capabilities of their generation, DR and EE, at least partially in response to the incentives and penalties contained in RPM as modified by CP changes.

After accounting for generation winter capacity, for FRR committed resources and for imports, total RPM capacity was 196,434.6 MW compared to 192,723.4 MW in the

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Requirement (FPR). Effective for the 2018/2019 and subsequent delivery years, the UCAP value of a load management product is equal to the ICAP value multiplied by the FPR. For the 2020/2021 BRA, this conversion factor was 1.0892. For the 2021/2022 BRA, this conversion factor was 1.0898. The DR Factor was designed to reflect the difference in losses that occur on the distribution system between the meter where demand is measured and the transmission system. The FPR multiplier is designed to recognize the fact that when demand is reduced by one MW, the system does not need to procure that MW or the associated reserve. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 6, Section B. See also "PJM Manual 20: PJM Resource Adequacy Analysis," Rev. 08 (July 1, 2017) at 12-14.

81 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9.

82 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Rev. 12 (Jan. 1, 2017) at 12. The manual states "the end of the next Delivery Year."

2020/2021 RPM Base Residual Auction.[83] Generation winter capacity increased by 125.5 MW, FRR volumes decreased by 102.8 MW, and imports decreased by 479.1 MW.[84] Of the 4,911.6 MW of imports, 441.2 MW were committed to an FRR capacity plan and 4,470.4 MW were offered in the auction, of which 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (51.6 percent) were from MISO. RPM capacity was reduced by exports of 1,295.0 MW, an increase of 1.7 MW from the 2020/2021 RPM Base Residual Auction. Of total exports, 670.3 MW (51.8 percent) were to NYISO, 547.6 MW (42.3 percent) were to MISO, and 77.1 MW (6.0 percent) were to Duke Energy Carolinas.

In addition, RPM capacity was reduced by (3,005.3) MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, by (1,397.6) MW of intermittent resources and (574.9) MW of capacity storage resources which were not subject to the CP must offer requirement, and by (3,017.5) MW which were excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (2,568.7 MW), the resource being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (233.3 MW), the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (141.5 MW), and significant physical operational restrictions (74.0 MW).[85] Subtracting 16.1 MW of FRR optional volumes not offered, an increase of 16.1 MW from the 2020/2021 RPM Base Residual Auction, 894.1 MW of DR and EE not offered, and 249.3 MW of unoffered generation winter capacity resulted in 185,984.8 MW that were available to be offered in the RPM Auction, an increase of 3,903.5 MW from the 2020/2021 RPM Base Residual Auction.[86] [87] After accounting for these factors, 437.8 MW were not offered and unexcused in the RPM Auction.

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83 The FRR alternative allows a load serving entity (LSE), subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

84 Unless otherwise specified, an annual equivalent MW quantity is used to report winter capacity, which is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

85 See OATT Attachment M-Appendix § II.C.4 for the reasons to qualify for an exception to the RPM must offer requirement.

86 FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The FRR optional MW are a combination of excess

Offered MW increased 3,465.8 MW from 182,081.2 MW to 185,547.0 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 1,194.5 MW from 154,355.3 MW to 153,160.8 MW from the 2020/2021 RPM Base Residual Auction. The RTO Reliability Requirement adjusted for FRR obligations is calculated as the RTO forecast peak load times the Forecast Pool Requirement (FPR), less FRR UCAP obligations. The FPR is calculated as (1+Installed Reserve Margin) times (1-Pool Wide Average EFORd), where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability.[88] The 1,194.5 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2020/2021 RPM Base Residual Auction was a result of a 1,289.1 MW decrease in the RTO Reliability Requirement not adjusted for FRR offset by a 94.6 MW decrease in the FRR obligation, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity decreased 1,267.6 MW from the 2020/2021 RPM Base Residual Auction to 152,647.4 MW. The 1,289.1 MW decrease in the RTO Reliability Requirement was a result of a (1,380.7) MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2020/2021 level offset by a 91.6 MW increase attributable to the change in the FPR. The increase in the FPR from the 2020/2021 RPM Base Residual Auction is a result of a decrease in the Pool Wide Average EFORd offset by a decrease in the IRM.

Table 17 shows the installed and offered generation capacity for the top five owners. The total installed capacity (203,896.0 MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2021/2022 RPM Base Residual Auction (198,147.3 ICAP MW), annual equivalent MW quantity for generation winter capacity (534.7 ICAP MW), and external resources offered or committed to an FRR plan (5,214.0 ICAP MW).

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volumes included in the sales cap amount which were not offered in the auction and volumes above the sales cap amount which were not permitted to offer in the auction.

87 Unoffered DR and EE MW include PJM approved DR plans and EE plans that were not offered in the auction.

88 PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 4.1.

Clearing Results

The Net Load Price that load serving entities (LSEs) will pay is equal to the Final Zonal Capacity Price less the final Capacity Transfer Rights (CTR) credit rate.[89] As shown in Table 12, the preliminary Net Load Price is $140.53 per MW-day in the RTO.

As shown in Table 10 and Table 11, the 160,795.3 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 22.0 percent and a net excess of 8,190.3 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW (Installed Reserve Margin (IRM) of 15.8 percent).[90] [91] [92] [93] Net excess decreased 1,461.2 MW from the net excess of 9,651.5 MW in the 2020/2021 RPM Base Residual Auction.[94] Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side results in a calculated reserve margin of 21.1 percent and a net excess of 7,431.8 MW over the reliability requirement adjusted for FRR and PRD of 152,605.0 MW. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $140.00 per MW-day.

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89 Effective with the 2012/2013 Delivery Year, Final Zonal Capacity Prices and the final CTR credit rate are determined after the final Incremental Auction.

90 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make whole MW less the reliability requirement plus ILR. For the 2012/2013 through the 2017/2018 Delivery Years, net excess under RPM is calculated as cleared capacity plus make whole MW less the reliability requirement plus the Short-Term Resource Procurement Target. For the 2018/2019 Delivery Year, the net excess under RPM is calculated as cleared capacity plus make whole MW less the reliability requirement. For the 2019/2020 and subsequent delivery years, the net excess under RPM is calculated as cleared generation and DR capacity plus make whole MW less the reliability requirement.

91 The IRM decreased from 16.6 percent in the 2020/2021 RPM Base Residual Auction to 15.8 percent in the 2021/2022 RPM Base Residual Auction.

92 The 22.0 percent reserve margin does not include EE on the supply side or the EE add back on the demand side. This is how PJM calculates the reserve margin.

93 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

94 The net excess calculation for the 2020/2021 RPM Base Residual Auction reported in the *Analysis of 2020/2021 RPM Base Residual Auction* has been revised.

Capacity market sellers are allowed to offer up to 10 sell offer segments for a resource and, for annual resources, specify a minimum MW quantity for every segment. The capacity market rules do not require the segments to be aligned with the physical operating attributes of the underlying capacity resource. In a competitive capacity market, there is no valid economic reason for capacity market sellers to specify a minimum MW quantity greater than 0 MW (inflexible sell offer segment) when offering a resource in multiple segments. A valid economic argument could be made for specifying a minimum MW quantity greater than 0 MW if the resource were offered as a single segment, representing one unit. The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.

If the market clears on a nonflexible sell offer segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make whole MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[95] The make whole payment for partially cleared resources equals the make whole MW times the clearing price. A more efficient solution could include not selecting a nonflexible segment from a lower priced offer and accepting a higher priced sell offer that does not include a minimum block MW requirement.[96] [97] The market results in the 2021/2022 BRA did not include make whole MW and payments resulting from partially cleared resources.

Make whole MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[98] [99] If an offer clears in an auction under either option and if a qualifying resource does not clear in the two subsequent BRAs, the process specified in the Tariff is triggered, and the resource is

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95 OATT Attachment DD § 5.14 (b).

96 OATT Attachment DD § 5.12 (a).

97 For more details on the make whole processing, see Attachment A.

98 OATT Attachment DD § 5.14 (c) (2).

99 OATT Attachment DD § 6.8 (a).

awarded a make whole payment.[100] The market results in the 2021/2022 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2021/2022 BRA did include seasonal make whole MW and payments. Under the seasonal capacity rules, the optimization considers the total cost of clearing a seasonal offer in combination with an offer for the opposite season, and this can and did result in clearing seasonal sell offers with prices greater than the clearing price and seasonal make whole payments being granted.

Table 18 shows offered and cleared MW by LDA, resource type, and season in the 2021/2022 RPM Base Residual Auction. Of the 171,249.8 MW of generation offers, 170,841.5 MW were for the annual season. Of the 11,494.0 MW of DR offers, 11,094.6 MW were for the annual season. Of the 2,803.2 MW of EE offers, 2,649.0 MW were for the annual season.

Table 19 shows the weighted average sell offer prices by LDA, resource type, and season. For generation, the weighted average sell offer prices in RTO for winter were greater than the weighted average sell offer prices for annual, which were greater than the weighted average sell offer prices for summer. For DR and EE, the weighted average sell offer prices in RTO for annual were greater than the weighted average sell offer prices for summer.

In the absence of data on the marginal cost of providing DR and EE, it is difficult to determine whether such resources are offered at levels equal to, greater than or less than marginal cost. If such resources are offered at prices in excess of marginal cost, the result would be prices greater than competitive levels. If such resources are offered at prices less than marginal cost, the result would be prices less than competitive levels. Both potential outcomes are of significant concern. The RPM rules exempt DR and EE resources from market power mitigation.

Table 20 shows the offered MW by resource type, offer/product type, and price range as percent of net CONE times B in the 2021/2022 RPM Base Residual Auction. Capacity Performance generation offers between 50 percent of net CONE times B and greater than 100 percent times net CONE times B increased by 7,888.2 MW from the 2020/2021 RPM Base Residual Auction.

Table 21 shows cleared MW by zone and fuel source. Of the 171,249.8 MW offered for generation resources, 149,997.6 MW cleared (87.6 percent). Of the 163,627.3 cleared MW in the entire RTO, 26,343.7 MW (16.1 percent) cleared in Dominion, followed by 22,358.1

[100] OATT Attachment DD § 5.14 (c) (2) (ii).

MW (13.7 percent) in ComEd and 16,810.7 MW (10.3 percent) in AEP. Of the 149,997.6 cleared MW for generation resources in the entire RTO, 75,946.7 MW (50.6 percent) were gas resources, followed by 41,193.6 MW (27.5 percent) from coal resources and 19,917.9 MW (13.3 percent) from nuclear resources. Cleared MW from nuclear resources decreased 7,473.1 from the 2020/2021 RPM Base Residual Auction while cleared MW from DR and EE resources increased 4,293.4 MW from the 2020/2021 RPM Base Residual Auction.

The 21,919.7 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 21,919.7 uncleared MW in the entire RTO, 74.9 MW were EE offers, 592.4 MW were DR offers, and the remaining 21,252.3 MW were generation offers.[101] Table 22 presents details on the generation offers that did not clear. Of the 21,252.3 MW of uncleared generation offers, 10,656.0 MW (50.1 percent) were for generation resources greater than 40 years old, and 10,596.3 MW (49.9 percent) were for generation resources less than or equal to 40 years old.

Table 23 shows the auction results for the prior two Delivery Years for the generation resources that did not clear some or all MW in the 2021/2022 BRA. Of the 269 generation resources that did not clear 21,252.3 MW in the 2021/2022 BRA, 137 of those generation resources did not clear 7,894.2 MW in RPM Auctions for the 2020/2021 Delivery Year. Of those 137 generation resources that did not clear MW in RPM Auctions for the 2021/2022 and 2020/2021 Delivery Years, 79 of those generation resources did not clear 4,711.5 MW in RPM Auctions for the 2019/2020 Delivery Year. Thus, 7,894.2 MW of capacity did not clear in two sequential auctions, but 4,711.5 MW did not clear in three sequential auctions.

Capacity Transfer Rights

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA is equal to the Unforced Capacity imported into the LDA determined based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants which include Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a

[101] Reported uncleared MW values are based on rounded annual equivalent MW values for seasonal offers.

transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a Delivery Year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $6,734,907, and COMED had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

Constraints in RPM Markets: CETO/CETL

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, PJM does a load deliverability analysis for each LDA.[102] The first step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the Capacity Emergency Transfer Limit (CETL), which is also expressed in unforced

[102] "PJM Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Rev. 41 (April 19, 2018) at 66. Manual 14B indicates that all "electrically cohesive load areas" are tested.

megawatts. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, the level of CETL, in combination with the internal LDA capacity resource supply curve, could result in locational price differences.[103]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction. Only modeled LDAs can price separate in an auction. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of these three tests.[104] In addition, PJM may decide to model an LDA even if it does not qualify under these tests if PJM finds that "such is required to achieve an acceptable level of reliability."[105] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

The CETL levels and the CETL/CETO ratios do not determine or predict whether there will be prices separation for an LDA. Locational price differences result from the interaction between the CETL import limit and the supply curve for capacity inside an LDA. The CETL could be very low and there would be no price separation if all the offers for internal capacity were low compared to offers for capacity outside the LDA. The CETL could be very high (but less than the demand for capacity in the LDA) and

103 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 24.

104 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

105 OATT Attachment DD § 5.10 (a) (ii).

there would be price separation if all the offers for internal capacity were high compared to offers for capacity outside the LDA.

Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints.

Table 24 shows the CETL and CETO values used in the 2021/2022 study compared to the 2020/2021 values. The CETL values for the ComEd and PSEG North LDAs changed significantly. The ComEd CETL increased due to "two baseline 345 kV transmission reconductoring projects in AEP (b2776 and b2777) as well as two baseline 345 kV transmission upgrades in COMED (b2930 and b2931) that were not included in the 2020/2021 BRA CETL power flow study."[106] The PSEG and PSEG North CETL decreased due to load deliverability rules approved by the PJM Markets & Reliability Committee (MRC), offset by the conversion of the HTP merchant transmission project's firm transmission withdrawal rights to nonfirm transmission withdrawal rights. Under the new rules, the transactions that are not secured with firm transmission rights are excluded from CETL studies. The PSEG CETL also decreased due to the suspension of the ISA for the Poseidon merchant transmission project.

PJM appears to recognize that it is not appropriate to include assumptions of any emergency imports, which are equivalent to assuming capacity imports from NYISO in the CETL studies. Prior to the 2021/2022 BRA, PJM included capacity imports and exports secured with both firm and nonfirm transmission in the CETL studies. Starting with the 2021/2022 BRA, PJM included only capacity imports and exports secured with firm transmission in the CETL studies. For the 2021/2022 BRA, all imports and exports secured with firm transmission that were approved and confirmed by PJM regardless of their approval status from the neighboring regions were included in CETL studies despite the fact that they were not and could not be capacity imports. PJM has made rule changes such that starting with the 2022/2023 BRA only those imports and exports secured with firm transmission that were approved and confirmed by all relevant

106 See PJM "2021/2022 RPM Base Residual Auction Planning Period Parameters" <http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-bra-planning-parameters-report.ashx?la=en> (February 1, 2018).

entities will be included in the CETL cases.[107] The MMU recommends that PJM not include any capacity imports, even those secured with firm transmission service, from neighboring regions in the CETL analyses. The imports are not capacity imports. Treating imports as a source of capacity, directly analogous to an import of capacity from within PJM, overstates the supply of capacity and suppresses the capacity price compared to the competitive level. In addition, the imports, despite firm reservation, are not guaranteed to perform under all conditions to meet PJM's capacity market obligations. If Transmission Loading Relief 5a or 5b is initiated, the transactions secured by firm transmission service could also be curtailed.[108] The imports from neighboring regions are not substitutes for PJM's internal capacity resources and should not be treated as substitutes.

Table 25 shows the initial and final PJM CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the proposed CETL values. The proposed CETL values equal the PJM updated values. PJM introduced updates to the PJM Transmission Planning Process in August 2017. Under the updated rules, the CETL for PSEG was reduced from 8,001 MW to 6,474 MW. The CETL for PSEG North LDA was reduced from 4,264 to 2,955 MW. PJM explained that the updates in the CETL values are due to aligning the PSEG-NYISO PAR settings to be consistent with the new protocols established by PJM operations group following the termination of ConEd Wheel agreements.[109] The information that resulted in a reduction in the CETL values was available prior to the 2020/2021 BRA and the proposed CETL values should have been calculated prior to the 2020/2021 BRA and implemented in the 2020/2021 BRA.

The Price Impacts of Constraints in the RPM Market

As is the case in locational energy markets, transmission constraints in the PJM capacity markets affect clearing prices both by increasing prices in constrained areas and decreasing prices in unconstrained areas. Conversely, removing constraints reduces prices in constrained areas and increases prices in unconstrained areas. The impact of transmission constraints on price separation and on total market revenues depends on the shapes of the supply and demand curves in LDAs.

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107 See proposed Revisions to "PJM Manual 14B: PJM Region Transmission Planning Process," presented at July 27, 2017 meeting of the Markets and Reliability Committee.

108 Additional details regarding the TLR procedure can be found in NERC. "*Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief*" (October 23, 2007).

109 See "CETO/CETL Education," presented at November 3, 2017 meeting of Special Planning Committee.

There were five locationally binding constraints in the 2021/2022 BRA which resulted in demand clearing in a locationally constrained LDA which did not clear in the RTO market or in contiguous or parent LDAs and which cleared at a higher price than in contiguous or parent LDAs. The result was to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.

Nested LDAs occur when a constrained LDA is a subset of a larger constrained LDA or the RTO. The supply and demand curves for nested LDAs can be presented in two different ways to illustrate the market clearing dynamic. The supply curves in the figures in this report, unless otherwise noted, show the total internal supply of the LDA, including all nested LDAs and not including CETL MW. The demand curve is reduced by the CETL and by the MW that cleared incrementally in the constrained, nested LDAs.

Impact of ComEd CETL (Scenario 1)

The ComEd CETL for the 2021/2022 RPM Base Residual Auction was 1,510.0 MW higher than the 2020/2021 ComEd CETL level, an increase of 37.2 percent. Table 26 shows the results if the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The results of the scenario show that the ComEd price for the 2021/2022 RPM Base Residual Auction was higher than it would have been if the CETL had remained at the lower 2020/2021 CETL value. This counter intuitive price impact was a result of the interaction of the supply offers and the demand curve.

All binding constraints would have remained the same except that the DEOK LDA is also binding. The RTO clearing price would have decreased to $112.75 per MW-day, and the clearing quantity would have increased to 164,508.9 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement remained the same at 1.0 MW. The PSEG clearing price would remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement remained the same at 1.0 MW. The BGE clearing price would have decreased to $180.50 per MW-day, and the clearing quantity would have increased to 1,959.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have increased to 23,901.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement remained the same at 274.5 MW. The DEOK clearing price would have decreased to $128.47 per MW-day and the clearing quantity would have decreased to 2,636.3 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the 2020/2021 CETL value for ComEd had been used in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,320,327,063, a decrease of $980,550,043, or 10.5 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for ComEd resulted in a 11.8 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been using the 2020/2021 CETL value for ComEd.

Impact of PSEG CETL Adjustment (Scenario 2)

PJM introduced updates to the PJM Region Transmission Planning Process and corrections to the CETL calculations in August 2017. The planning process updates stem from the termination of the ConEd Wheel Agreement. The updates included changes to the PJM NYISO PAR flows and PJM will no longer assume nonfirm import capacity from outside PJM is available when determining the CETL values for MAAC, EMAAC, PSEG, and PSEG North.[110] Table 25 shows the CETL values for MAAC, EMAAC, PSEG, and PSEG North for the 2020/2021 BRA and the 2021/2022 BRA, and the proposed CETL values from August 2017.

The 2021/2022 CETL value for MAAC is 4,019 which is 199 MW less than the 2020/2021 MAAC CETL value and 901 MW greater than the August 2017 value. The 2021/2022 CETL value for EMAAC is 9,000 which is 200 MW greater than the 2020/2021 EMAAC CETL value and 700 MW greater than the August 2017 value. The 2021/2022 CETL value for PSEG is 6,902 which is 1,099 MW less than the 2020/2021 MAAC CETL value and 428 MW greater than the August 2017 value. The 2021/2022 CETL value for PSEG North is 3,180 which is 1,084 MW less than the 2020/2021 MAAC CETL value and 225 MW greater than the August 2017 value.

PJM included power flows associated with capacity imports and exports secured with firm transmission from neighboring regions in calculating CETL values between LDAs.

110 See "M14B Updates," presented at August 10, 2017, meeting of Planning Committee.

To approximate the impact of power flows associated with imports from New York ISO, a sensitivity with a 200.0 MW reduction in the CETL value for PSEG LDA was used.

Table 27 shows the results if the PSEG CETL value was reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $140.00 per MW-day and the clearing quantity would have remained the same at 163,627.3 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have increased to 29,290.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have increased to $206.58 per MW-day, and the clearing quantity would have increased to 5,562.2 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have remained the same at $195.55 per MW-day, and the clearing quantity would have remained the same at 22,358.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the PSEG CETL value was reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,306,030,179, an increase of $5,153,073, or 0.1 percent, compared to the actual results. From another perspective, the use of the 2021/2022 CETL value for PSEG LDA resulted in a 0.1 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the CETL value for PSEG LDA been reduced by 200.0 MW in the 2021/2022 RPM Base Residual Auction.

Impact of the Forecast Peak Load (Scenario 3)

The accuracy of the peak load forecast has a significant impact on RPM Base Residual Auction results. Table 45 summarizes the peak load forecasts for the RPM auctions held since May 2010. The peak load forecast for the Third IA has historically been lower than the peak load forecast used in the corresponding BRA. The Third IA is the last auction prior to the beginning of the delivery year, and the peak load forecast for the Third IA provides the best indicator of the capacity needed to meet the reliability criterion. For the five delivery years from 2014/2015 through 2018/2019, the peak load forecast for the Third IA has been on average 5.8 percent lower than the peak load forecast used in the corresponding BRA.

Table 28 shows the results if the peak load forecast had been reduced by 5.8 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same except that the DEOK LDA is also binding. The RTO clearing price would have decreased to $80.00 per MW-day, and the clearing quantity would have decreased to 155,349.8 MW. The amount of cleared seasonal capacity would have decreased to 623.5 MW. The ATSI clearing price would have increased to $226.40 per MW-day, and the clearing quantity would have decreased to 6,889.1 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $139.46 per MW-day, and the clearing quantity would have decreased to 27,310.0 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $160.00 per MW-day, and the clearing quantity would have decreased to 4,776.5 MW. The clearing quantity for seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $178.77 per MW-day, and the clearing quantity would have decreased to 1,492.6 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $198.48 per MW-day, and the clearing quantity would have decreased to 20,772.7 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW. The DEOK clearing price would have decreased to $107.23 per MW-day and the clearing quantity would have decreased to 2,284.4 MW. The clearing quantity of seasonal capacity cleared for satisfying DEOK's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the peak load forecast for the 2021/2022 RPM Base Residual Auction had been 5.8 percent lower and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $6,510,513,224, a decrease of $2,790,363,882, or 30.0 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2021/2022 Base Residual Auction resulted in a 42.9 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 5.8 percent below the PJM peak load forecast. (Scenario 3)

Impact of Rightward Shift of the VRR Curve (Scenario 4)

Beginning with the 2018/2019 RPM Base Residual Auction, PJM has included a one percent rightward shift in the VRR curve to mitigate certain low probability risks. The shift was recommended by the Brattle Group to lower the probability of under procuring capacity in the event of a supply or demand shock, or underestimating net CONE.[111] PJM provided additional details regarding the shift to the Commission, basing the need for the VRR curve shift on uncertainty of supply due to the Mercury and Air Toxic Standards (MATS), the vacating of Order 745, the EPA's Greenhouse Gas Rule, and advances in combined cycle generation.[112] The Commission approved the change noting "PJM appropriately accounted for this modeling inadequacy and the underlying potential for supply shifts with a more conservative VRR Curve, i.e., with a VRR Curve that will result in the procurement of additional capacity."[113]

Table 29 shows the results of the 2021/2022 RPM Base Residual Auction had the VRR curve not included a one percent rightward shift and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have decreased to $129.43 per MW-day, and the clearing quantity would have decreased to 162,646.5 MW. The amount of cleared seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,963.5 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,983.4 MW. The clearing quantity for seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $194.47 per MW-day, and the clearing quantity would have decreased to 5,291.5 MW. The clearing quantity for seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $178.77 per MW-day, and the clearing quantity would have decreased to 1,895.2 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $184.04 per MW-day, and the clearing

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111 See PJM "Third Triennial Review of PJM's Variable Resource Requirement Curve" <http://www.pjm.com/-/media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curve-report.ashx?la=en> (May 15, 2014) at 68.

112 149 FERC ¶ 61,183 at P 25 (2014).

113 Ibid at P. 52.

quantity would have decreased to 22,191.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the VRR curve for the 2021/2022 RPM Base Residual Auction had not included a one percent shift to the right and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,648,601,896, a decrease of $652,275,210, or 7.0 percent, compared to the actual results. From another perspective, shifting the VRR curve to the right by one percent for the 2021/2022 Base Residual Auction resulted in a 7.5 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what revenues would have been had the VRR curve not been shifted. (Scenario 4)

Composition of the Steeply Sloped Portion of the Supply Curve

Table 30 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day. Offers for DR and EE resources were 6.6 percent of the offers greater than $35.00 per MW-day compared to 6.2 percent in the 2020/2021 RPM Base Residual Auction. Offers for coal fired units made up 30.8 percent of the offers greater than $35.00 per MW-day compared to 35.0 percent in the 2020/2021 RPM Base Residual Auction. Offers for nuclear units made up 19.9 percent of the offers greater than $35.00 per MW-day compared to 10.1 percent in the 2020/2021 RPM Base Residual Auction.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2021/2022 BRA:[114] [115]

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114 Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered in RPM Auctions as capacity resources and receive the clearing price.

115 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the Second Incremental Auction. The ILR product was eliminated as of the 2012/2013 Delivery Year.

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.

- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[116] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending 1500 and the hour ending 1800 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[117]

Effective for the 2014/2015 through the 2017/2018 Delivery Years, there are three types of Demand Resource products included in the RPM market design:[118] [119]

- **Annual DR.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

- **Extended Summer DR.** A Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be

116 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section M.

117 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

118 134 FERC ¶ 61,066 (2011).

119 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.

- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:[120] [121]

- **Base Capacity Resources**
    - **Base Capacity Demand Resources.** A Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
    - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Base Capacity Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
    - **Annual Demand Resources.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each

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120 151 FERC ¶ 61,208.

121 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

- **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - **Annual Demand Resources**
  - **Annual Energy Efficiency Resources**
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A Demand Resource that is required to be available on any day from June through October and the following May of the Delivery Year for an unlimited number of interruptions. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

Table 31 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2021/2022 RPM Base Residual Auction compared to the 2020/2021 RPM Base Residual Auction. Offers for DR increased from 9,113.0 MW in the 2020/2021 BRA to 11,494.0 MW in the 2021/2022 BRA, an increase of 2,380.9 MW or 26.1 percent. Offers for EE increased from 2,042.4 MW in the 2020/2021 BRA to 2,803.2 MW in the 2021/2022 BRA, an increase of 760.7 MW or 37.2 percent.

Impact of All DR and EE (Scenario 5)

Table 32 shows the results if there were no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.11 per MW-day, and the clearing quantity would have decreased to 158,125.4 MW. The clearing quantity of seasonal capacity would have decreased to 106.2 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $189.11 per MW-day, and the clearing quantity would have decreased to 28,481.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,983.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have decreased to $189.11 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.11 per MW-day, and the clearing quantity would have decreased to 21,719.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for DR or EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,030,339,776, an increase of $1,729,462,670, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 15.7 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

Impact of All EE (Scenario 6)

Table 33 shows the results if there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the DEOK constraint would have also been binding. The RTO clearing price would have decreased to $127.28 per MW-day, and the clearing quantity would have decreased to 160,125.8 MW. The clearing quantity of seasonal resources would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,843.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,361.8 MW. The clearing quantity of seasonal resources for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $179.16 per MW-day, and the clearing quantity would have decreased to 5,049.6 MW. The clearing quantity of seasonal resources for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $191.18 per MW-day, and the clearing quantity would have decreased to 1,834.1 MW. The clearing quantity of seasonal resources for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 21,548.2 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 172.2 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,512.9 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for EE and the EE add back MW were removed in the 2021/2022 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,450,275,422, a decrease of $850,601,684, or 9.1 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resource offers and the EE add back MW resulted in a 10.1 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE Resources did not participate on the supply side.

Impact of Annual DR and EE (Scenario 7)

Table 34 shows the results if there were no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The

ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.10 per MW-day, and the clearing quantity would have decreased to 158,398.2 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,614.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $189.10 per MW-day, and the clearing quantity would have decreased to 28,483.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,985.5 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 21,637.2 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,048,633,706, an increase of $1,747,756,600, or 18.8 percent, compared to the actual results. From another perspective, the inclusion of Annual Demand Resources and Annual Energy Efficiency resources resulted in a 15.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Annual Demand Resources or Annual Energy Efficiency resources.

Impact of Seasonal DR and Seasonal EE (Scenario 8)

Table 35 shows the results if there were no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have remained the same at $140.00 per MW-day, and the clearing quantity would have decreased to 163,222.5 MW. The clearing quantity of seasonal capacity would have decreased to 106.2 MW. The ATSI clearing price would have decreased to $166.26 per MW-day, and the clearing quantity would have decreased to 8,005.8 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have decreased to 29,229.3 MW.

The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.5 MW. The PSEG clearing price would have decreased to $198.45 per MW-day, and the clearing quantity would have decreased to 5,356.0 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0.5 MW. The BGE clearing price would have decreased to $198.69 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $190.79 per MW-day, and the clearing quantity would have decreased to 22,255.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal DR or Seasonal EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,207,711,533, a decrease of $93,165,573, or 1.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal Demand Resources and Seasonal Energy Efficiency resources resulted in a 1.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal Demand Resources or Seasonal Energy Efficiency resources.

The results show that the inclusion of additional Seasonal DR and Seasonal EE caused price increases in some LDAs and a higher RPM market revenue total. One factor leading to this counter intuitive result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the counter intuitive result.

Impact of Seasonal Capacity (Scenario 9)

Table 36 shows the results if there were no offers for Seasonal products (Demand Resources, Energy Efficiency Resources, and Generation Resources) in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $142.49 per MW-day, and the clearing quantity would have decreased to 163,142.0 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The ATSI clearing price would have decreased to $166.26 per MW-day, and the clearing quantity would have decreased to 8,005.8 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.47 per MW-day, and the clearing quantity would have decreased to 29,229.3 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have decreased to $198.66 per MW-day, and the clearing quantity would have decreased to 5,355.5 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have decreased to $198.69 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $190.79 per MW-day, and the clearing quantity would have decreased to 22,255.9 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,296,441,218, a decrease of $4,435,888, or 0.0 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources resulted in a 0.0 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal resources.

The results show that the inclusion of seasonal offers caused price increases in some LDAs and a higher RPM market revenue total. One factor leading to this counter intuitive result is that the EE add back MW for Seasonal Energy Efficiency adjustment to the VRR curve is larger than the amount of Seasonal Energy Efficiency offers, and therefore removing the Seasonal Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the result.

Impact of DR, EE, and Seasonal Capacity (Scenario 10)

Table 37 shows the results if there were no offers for Seasonal products as well as no offers for Annual DR or Annual EE in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI and the PSEG constraints would have been binding. The RTO clearing price would have increased to $189.12 per MW-day, and the clearing quantity would have decreased to 158,125.1 MW. The clearing quantity of seasonal capacity would have decreased to 0.0 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0.0 MW. The EMAAC clearing price would have increased to $189.12 per MW-day, and the clearing quantity would have decreased to 28,481.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.0 MW. The PSEG clearing price would have increased to $207.08 per MW-day, and the clearing quantity would have decreased to 4,983.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0.0 MW. The BGE clearing price would have decreased to $189.12 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have decreased to $189.12 per MW-day, and the clearing quantity would have decreased to 21,825.0 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0.0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for Seasonal products or demand side products in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,031,353,576, an increase of $1,730,476,470, or 18.6 percent, compared to the actual results. From another perspective, the inclusion of Seasonal resources, DR and EE resources resulted in a 15.7 percent decrease in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any Seasonal, DR, or EE resources.

The results show that the inclusion of seasonal offers, Annual DR, and Annual EE caused price increases in some LDAs. One factor leading to this counter intuitive result is that the EE add back MW adjustment to the VRR curve is larger than the amount of Energy Efficiency offers, and therefore removing the Energy Efficiency resources had a larger impact on demand than supply. The interaction of the supply offers and the demand curve also contributed to the result.

Impact of Winter Resources (Scenario 11)

Table 38 shows the results if offers from winter resources were reduced by 50 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $141.31 per MW-day, and the clearing quantity would have decreased to 163,584.9 MW. The clearing quantity of seasonal capacity would have decreased to 358.9 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0.0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0.5 MW. The PSEG clearing price would have increased to $204.50 per MW-day, and the clearing quantity would have decreased to 5,367.1 MW. The clearing quantity of seasonal capacity for satisfying

PSEG's reliability requirement would have decreased to 0.5 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW. The ComEd clearing price would have decreased to $184.04 per MW-day, and the clearing quantity would have increased to 22,417.4 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 137.7 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers from Winter resources were reduced by 50 percent in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,271,942,523, a decrease of $28,934,583, or 0.3 percent, compared to the actual results. From another perspective, the inclusion of all offers from winter resources resulted in a 0.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers from winter resources had been reduced by 50 percent.

Impact of Seasonal Matching Across LDAs (Scenario 12)

Table 39 shows the results if Seasonal offers were only matched with complementary Seasonal offers within the same LDA in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. All LDA clearing prices and clearing amounts would have remained the same and total RPM market revenues would have remained the same at $9,300,877,106.

In the 2021/2022 RPM Base Residual Auction, the proportion of low priced offers for summer in the rest of the RTO, the lowest common parent for all LDAs, substantially increased from the 2020/2021 RPM Base Residual Auction. Restricting the matching of complementary seasonal products to the LDA in which they are located means that a resource that did not clear for a lower LDA such as PSEG could not be matched with a complementary seasonal product in a higher LDA such as rest of the RTO. However, the availability of similarly lower priced offers located in the rest of RTO resulted in no difference in clearing quantities and prices when the seasonal matching was restricted to be within the same LDA where the resources were physically located.

Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[122] [123] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead market.[124]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[125] [126] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability

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122 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

123 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 62-65 & 89-90.

124 OATT, Schedule 1, Section 1.10.1A.

125 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.

126 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 66-68.

requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[127] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[128]

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant Delivery Year due to the curtailment of firm transmission by third parties.[129] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant Delivery Year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external Generation Capacity Resource must obtain an exception to the CIL to be eligible to offer as a Capacity Performance Resource.[130]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that has previously cleared an RPM auction.[131] The rule changes include defining coordination with other Balancing Authorities when conducting pseudo tie studies, establishing an electrical distance requirement, establishing a market-to-market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo-tie, a model consistency requirement, the requirement for the capacity market

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127 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

128 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

129 147 FERC ¶ 61,060 (2014).

130 151 FERC ¶ 61,208 (2015).

131 161 FERC ¶ 61,197 (2017).

seller to provide written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM, the requirement for the capacity market seller to obtain long-term firm point-to-point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM, establishing an operationally deliverable standard, and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at sub-regional transmission organization granularity.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA.

Table 40 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2021/2022 RPM Base Residual Auctions. The highest level of offered (7,493.7 MW) and cleared (7,482.7 MW) imports occurred in the 2016/2017 RPM BRA, which was prior to the implementation of the CIL rules. Of the 4,470.4 MW of imports offered in the 2021/2022 RPM BRA, 4,051.8 MW (90.6 percent) cleared.

Impact of Imports (Scenario 13, Scenario 14, Scenario 15, Scenario 16)

Reduction by 25 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 RPM Base Residual Auction had been reduced by 25 percent and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $149.47 per MW-day, and the clearing quantity would have decreased to 163,320.8 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have remained the same at $165.73 per MW-day, and the clearing quantity would have remained the same at 29,288.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The

ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,589,433,567, an increase of $288,556,461, or 3.1 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 3.0 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 25 percent.[132]

Reduction by 75 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 RPM Base Residual Auction had been reduced by 75 percent and everything else had remained the same. All binding constraints would have remained the same, except that the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $170.00 per MW-day, and the clearing quantity would have decreased to 162,656.6 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $170.00 per MW-day, and the clearing quantity would have increased to 29,318.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW.

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132 This analysis does not account for the fact that reduced imports could have a positive impact on CETL and an associated impact on clearing prices.

The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $10,350,916,800, an increase of $1,050,039,694, or 11.3 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 10.1 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 75 percent.

Reduction by 100 Percent

Table 41 shows the results if import offers for external generation resources in the 2021/2022 RPM Base Residual Auction had been reduced by 100 percent and everything else had remained the same. All binding constraints would have remained the same, except that the ATSI import limit and the EMAAC import limit would not have been binding. The RTO clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have decreased to 162,571.1 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $172.64 per MW-day, and the clearing quantity would have increased to 29,394.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $184.05 per MW-day, and the clearing quantity would have increased to 22,417.3 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 100 percent and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual

Auction would have been $10,427,509,062, an increase of $1,126,631,956, or 12.1 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 10.8 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 100 percent.

Impact of All DR, Seasonal Resources, and Capacity Imports (Scenario 17)

Table 42 shows the results if import offers for external generation resources had been reduced by 100 percent, there were no offers for DR or EE and no Seasonal resources in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. The ATSI import limit would have been the only binding constraint. The RTO clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have decreased to 157,509.1 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The ATSI clearing price would have increased to $216.83 per MW-day, and the clearing quantity would have decreased to 7,595.6 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 29,638.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have decreased to 0 MW. The PSEG clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have decreased to 5,127.4 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have decreased to 0 MW. The BGE clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 2,839.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have increased to $208.16 per MW-day, and the clearing quantity would have increased to 22,707.1 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have decreased to 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If offers for external generation were reduced by 100 percent and there were no offers for DR or EE and no Seasonal resources, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $11,997,162,266, an increase of $2,696,285,160, or 29.0 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources, and DR, EE, and Seasonal resources resulted in a 22.5 percent reduction in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 100 percent and there were no offers for DR or EE and no Seasonal resources.

Impact of Inconsistency Between EE Cleared MW and EE Add Back MW (Scenario 18)

PJM adjusts the VRR curve by adding the EE add back MW to the reliability requirement for each LDA. The EE add back MW is determined by PJM after a review of the EE measurement and verification plans.[133] If the ratio of the EE add back MW to cleared EE MW in the BRA exceeds a predetermined threshold, then PJM adjusts the EE add back MW and reruns the auction clearing a second and final time. For the 2021/2022 RPM Base Residual Auction, PJM cleared 2,832.0 MW of EE and the EE add back MW was equal to 3,912.9 for the aggregate RTO LDA. The resulting ratio, 1.38167373, did not exceed the threshold ratio of 1.606739475. Even though the threshold was not exceeded, the EE add back MW exceeded the EE cleared MW by 1,080.9 MW. Increasing demand due to the EE add back implementation had a significant impact on 2021/2022 RPM BRA results. Table 43 shows the results if adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2021/2022 RPM Base Residual Auction, and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have decreased to $132.68 per MW-day, and the clearing quantity would have decreased to 162,803.4 MW. The clearing quantity of Seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $145.00 per MW-day, and the clearing quantity would have decreased to 7,985.5 MW. The clearing quantity of Seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $165.00 per MW-day, and the clearing quantity would have decreased to 28,945.5 MW. The clearing quantity of Seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have decreased to $179.58 per MW-day, and the clearing quantity would have decreased to 5,269.3 MW. The clearing quantity of Seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $191.18 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of Seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.10 per MW-day, and the clearing quantity would have decreased to 22,312.5 MW. The clearing quantity of Seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

133 "PJM Manual 18: PJM Capacity Market," Rev. 40 (Feb. 22, 2018) at 32-34.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2021/2022 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,797,549,143, a decrease of $503,327,963, or 5.4 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW, resulted in a 5.7 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA.

Impact of Price Responsive Demand (Scenario 19)

Table 44 shows the results if there were no offers for PRD in the 2021/2022 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price would have increased to $142.60 per MW-day, and the clearing quantity would have increased to 164,099.0 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have remained the same at $171.33 per MW-day, and the clearing quantity would have remained the same at 8,007.3 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $172.33 per MW-day, and the clearing quantity would have increased to 29,318.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $180.50 per MW-day, and the clearing quantity would have increased to 2,221.2 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $189.01 per MW-day, and the clearing quantity would have increased to 22,391.8 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If there were no offers for PRD in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $9,424,270,494, an increase of $123,393,388, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 1.3 percent reduction in RPM revenues for the

2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD.

The results show that the inclusion of PRD caused price increases in some LDAs. The interaction of the supply offers and the demand curve also contributed to this counter intuitive result.

Impact of Nuclear Offers (Scenario 20)

Nuclear offer behavior changed in the 2021/2022 RPM Base Residual Auction compared to prior auctions. More nuclear capacity was offered at higher sell offer prices and fewer nuclear MW cleared.[134] (See Table 21, Table 22, and Table 30) To define an upper bound on the impact of nuclear offers, a scenario setting all nuclear offers to $0 per MW-day was analyzed. The MMU does not assert that a $0 per MW-day sell offer was a competitive offer for all nuclear resources.

Table 46 shows the results of the 2021/2022 RPM Base Residual Auction had all nuclear offers been replaced with $0 per MW-day and everything else had remained the same. The EMAAC, PSEG, and BGE import constraints would have remained binding and the DEOK import constraint would have been binding. The ATSI and ComEd import constraints would not be binding. The RTO clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 165,844.3 MW. The clearing quantity of seasonal capacity would have decreased to 587.6 MW. The ATSI clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 8,603.4 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $125.94 per MW-day, and the clearing quantity would have increased to 29,598.6 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have remained the same at $200.30 per MW-day, and the clearing quantity would have remained the same at 1,937.7 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $71.48 per MW-day, and the clearing quantity would have increased to 24,499.4 MW. The clearing quantity of seasonal

134 See PJM. News Releases, May 23, 2018. <http://www.pjm.com/-/media/about-pjm/newsroom/2018-releases/20180523-rpm-results-2021-2022-news-release.ashx>.

capacity for satisfying ComEd's reliability requirement would have decreased to 154.4 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,636.3 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If all nuclear offers were replaced by $0 per MW-day in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $5,215,048,770, a decrease of $4,085,828,337, or 43.9 percent, compared to the actual results. From another perspective, nuclear offers at levels exceeding $0 per MW-day resulted in a 78.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day.

Noncompetitive Offers (Scenario 21)

The MMU identified noncompetitive offers that had a significant impact on the 2021/2022 RPM Base Residual Auction results.

Some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The PJM tariff defines the balancing ratio (B) used in the default offer cap as the average of balancing ratios during the actual performance assessment intervals that occurred during the three calendar years preceding the auction.[135] PJM did not experience any

[135] OATT Attachment DD § 6.4(a).

performance assessment intervals during the three year period that preceded the 2021/2022 RPM Base Residual Auction and the balancing ratio calculation was not feasible. PJM resolved the balancing ratio issue by changing the tariff to state that the balancing ratio for the 2021/2022 RPM Base Residual Auction would equal the balancing ratio value used for the 2020/2021 RPM Base Residual Auction.[136] PJM did not propose any updates to the nonperformance charge rate or the default offer cap definition of net CONE times B. In doing so, PJM continued to assume an expected 30 hours, or 360 intervals, of PAIs for the 2021/2022 delivery year. This assumption is not consistent with the recent history of emergency actions in the PJM energy market. The correct way to account for the lack of performance assessment intervals during the three year history would have been to recognize that this means that unit specific net ACR is the offer cap under the capacity performance construct. This would have been consistent with a market participant having an expectation of a very low number of performance assessment intervals. This would have been consistent with the competitive offer calculation logic that PJM filed in response to a deficiency letter issued by the Commission in the Capacity Performance docket.[137]

Table 47 shows the results if the noncompetitive offers identified by the MMU had been capped at net ACR for the 2021/2022 RPM Base Residual Auction. All binding constraints would have remained the same except that the BGE import constraint would not have been binding and the DEOK import constraint would have been binding. The RTO clearing price would have decreased to $124.40 per MW-day, and the clearing quantity would have increased to 164,132.1 MW. The clearing quantity of seasonal capacity would have remained the same at 715.5 MW. The ATSI clearing price would have decreased to $169.65 per MW-day, and the clearing quantity would have increased to 8,013.1 MW. The clearing quantity of seasonal capacity for satisfying ATSI's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $155.93 per MW-day, and the clearing quantity would have increased to 29,364.9 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 1.0 MW. The PSEG clearing price would have remained the same at $204.29 per MW-day, and the clearing quantity would have remained the same at 5,367.6 MW. The clearing quantity of seasonal capacity for satisfying PSEG's reliability requirement would have remained the same at 1.0 MW. The BGE clearing price would have decreased to $124.40 per MW-day,

[136] *See* PJM. "Reliability Pricing Model Offer Cap Tariff Revision for 2018 Base Residual Auction," Docket No. ER18-262 (November 7, 2017).

[137] *See* PJM. "Response of PJM Interconnection, L.L.C. to Commission's March 31, 2015 Information Request," Docket No. ER15-623 (April 10, 2015).

and the clearing quantity would have increased to 2,492.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW. The ComEd clearing price would have decreased to $130.04 per MW-day, and the clearing quantity would have increased to 22,695.5 MW. The clearing quantity of seasonal capacity for satisfying ComEd's reliability requirement would have remained the same at 274.5 MW. The DEOK clearing price would have decreased to $128.47 per MW-day, and the clearing quantity would have decreased to 2,636.3 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2021/2022 RPM Base Residual Auction were $9,300,877,106. If the identified noncompetitive offers had been capped at net ACR in the 2021/2022 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2021/2022 RPM Base Residual Auction would have been $8,070,050,631, a decrease of $1,230,826,475, or 13.2 percent, compared to the actual results. From another perspective, the noncompetitive offers resulted in a 15.3 percent increase in RPM revenues for the 2021/2022 RPM Base Residual Auction compared to what RPM revenues would have been had the noncompetitive offers been capped at net ACR.

Tables and Figures for RTO Market

Table 9 RTO offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	198,147.3	189,028.5		
DR capacity	11,641.3	12,686.7		
EE capacity	2,728.9	2,975.2		
Generation winter capacity	534.7	534.7		
Total internal RTO capacity	213,052.2	205,225.1		
FRR	(14,578.3)	(13,702.1)		
Imports	5,214.0	4,911.6		
RPM capacity	203,687.9	196,434.6		
Exports	(1,319.8)	(1,295.0)		
FRR optional	(17.3)	(16.1)		
Excused Existing Generation Capacity Resources	(4,110.3)	(3,017.5)		
Unoffered Planned Generation Capacity Resources	(3,141.2)	(3,005.3)		
Unoffered Intermittent Resources	(1,482.8)	(1,397.6)		
Unoffered Capacity Storage Resources	(580.9)	(574.9)		
Unoffered generation winter capacity	(249.3)	(249.3)		
Unoffered DR and EE	(812.4)	(894.1)		
Available	191,973.9	185,984.8	100.0%	100.0%
Generation offered	178,410.1	171,249.8	92.9%	92.1%
DR offered	10,551.3	11,494.0	5.5%	6.2%
EE offered	2,574.6	2,803.2	1.3%	1.5%
Total offered	191,536.1	185,547.0	99.8%	99.8%
Unoffered Existing Generation Capacity Resources	437.8	437.8	0.2%	0.2%

Table 10 Reserve margin: 2021/2022 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load	152,647.4	A
FRR peak load	12,107.1	B
PRD	510.0	C
IRM	15.8%	D
Pool-wide average EFORd	5.89%	E
Cleared UCAP (generation and DR)	160,795.3	F
Cleared ICAP (generation and DR)	170,858.9	G=F/(1-E)
RPM peak load	140,030.3	H=A-B-C
Reserve margin	22.0%	J=(G/H)-1
Reserve cleared in excess of IRM	6.2%	J-D

Table 11 Net excess: 2021/2022 RPM Base Residual Auction

	UCAP (MW)						
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE	
Cleared generation and DR plus make whole	160,795.3	28,671.5	5,127.5	7,859.1	21,587.6	1,833.3	A
CETL	NA	9,000.0	6,902.0	8,439.0	5,574.0	6,005.0	B
Reliability requirement	166,355.1	35,994.0	11,501.0	15,598.0	26,112.0	7,910.0	C
FRR peak load	12,107.1	0.0	0.0	0.0	0.0	0.0	D
PRD	510.0	75.0	0.0	0.0	0.0	240.0	E
FPR	1.0898	1.0898	1.0898	1.0898	1.0898	1.0898	F
Reliability requirement adjusted for FRR and PRD	152,605.0	35,912.3	11,501.0	15,598.0	26,112.0	7,648.4	G=C-D*F-E*F
Net excess/(deficit)	8,190.3	1,759.2	528.5	700.1	1,049.6	189.9	A+B-G

Table 12 Net load prices: 2021/2022 RPM Base Residual Auction

	$ per MW-day					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Resource clearing price	$140.00	$165.73	$204.29	$171.33	$195.55	$200.30
Preliminary zonal capacity price	$140.02	$165.75	$204.31	$171.35	$195.57	$200.32
Adjusted preliminary zonal capacity price	$140.53	$166.31	$204.92	$171.86	$196.08	$203.19
Base zonal CTR credit rate	$0.00	$3.23	$20.88	$13.87	$3.40	$41.57
Preliminary net load price	$140.53	$163.08	$184.03	$157.99	$192.69	$161.62

Table 13 Capacity modifications (ICAP): 2021/2022 RPM Base Residual Auction[138]

	ICAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	3,403.8	110.4	38.4	24.7	178.7	0.0
Generation decreases	(1,093.2)	(32.5)	(0.6)	(40.7)	(20.8)	0.0
Capacity modifications net increase/(decrease)	2,310.6	77.9	37.8	(16.0)	157.9	0.0
DR increases	2,271.3	262.4	75.0	350.6	199.3	5.6
DR decreases	(1,303.0)	(230.4)	(42.6)	(323.7)	(118.7)	(100.6)
DR net increase/(decrease)	968.3	32.0	32.4	26.9	80.6	(95.0)
EE increases	1,827.1	495.8	196.4	146.4	239.2	30.5
EE decreases	(1,283.0)	(240.5)	(66.6)	(48.3)	(267.2)	(80.6)
EE modifications increase/(decrease)	544.1	255.3	129.8	98.1	(28.0)	(50.1)
Net internal capacity increase/(decrease)	3,823.0	365.2	200.0	109.0	210.5	(145.1)

138 Only cap mods that had a start date on or before June 1, 2021 and DR and EE plans for the 2021/2022 RPM Base Residual Auction are included.

Table 14 Capacity modifications (UCAP): 2021/2022 RPM Base Residual Auction

	UCAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	3,335.0	106.8	35.3	58.3	178.0	0.0
Generation decreases	(868.0)	(27.3)	(0.6)	(39.4)	(20.2)	0.0
Capacity modifications net increase/(decrease)	2,467.0	79.5	34.7	18.9	157.8	0.0
DR increases	2,474.3	286.0	81.7	381.9	217.1	6.1
DR decreases	(1,418.4)	(250.4)	(46.3)	(352.5)	(129.3)	(109.7)
DR net increase/(decrease)	1,055.9	35.6	35.4	29.4	87.8	(103.6)
EE increases	1,990.3	540.2	214.2	159.5	260.4	33.2
EE decreases	(1,395.9)	(261.0)	(72.4)	(52.5)	(291.1)	(87.9)
EE modifications increase/(decrease)	594.4	279.2	141.8	107.0	(30.7)	(54.7)
Net capacity/DR/EE modifications increase/(decrease)	4,117.3	394.3	211.9	155.3	214.9	(158.3)
EFORd effect	(164.6)	226.8	34.2	(235.7)	118.4	55.5
DR and EE effect	9.3	1.1	0.3	1.0	1.8	0.5
Net internal capacity increase/(decrease)	3,962.0	622.2	246.4	(79.4)	335.1	(102.3)

Table 15 Winter capacity modifications (ICAP): 2021/2022 RPM Base Residual Auction

	ICAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	359.6	0.0	0.0	0.0	179.9	0.0
Generation decreases	(106.5)	0.0	0.0	0.0	(67.4)	0.0
Capacity modifications net increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0

Table 16 Winter capacity modifications (UCAP): 2021/2022 RPM Base Residual Auction

	UCAP (MW)					
	RTO	EMAAC	PSEG	ATSI	ComEd	BGE
Generation increases	359.6	0.0	0.0	0.0	179.9	0.0
Generation decreases	(106.5)	0.0	0.0	0.0	(67.4)	0.0
Capacity modifications net increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
DR increases	0.0	0.0	0.0	0.0	0.0	0.0
DR decreases	0.0	0.0	0.0	0.0	0.0	0.0
DR net increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
EE increases	0.0	0.0	0.0	0.0	0.0	0.0
EE decreases	0.0	0.0	0.0	0.0	0.0	0.0
EE modifications increase/(decrease)	0.0	0.0	0.0	0.0	0.0	0.0
Net capacity/DR/EE modifications increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0
EFORd effect	0.0	0.0	0.0	0.0	0.0	0.0
DR and EE effect	0.0	0.0	0.0	0.0	0.0	0.0
Net internal capacity increase/(decrease)	253.1	0.0	0.0	0.0	112.5	0.0

Table 17 Installed and offered generation capacity by parent company: 2021/2022 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Dominion Resources, Inc.	22,866.2	11.2%	22,797.5	12.8%
Exelon Corporation	22,353.0	11.0%	21,337.1	12.0%
American Electric Power Company, Inc.	16,922.3	8.3%	3,039.1	1.7%
NRG Energy, Inc.	15,339.0	7.5%	15,300.6	8.6%
FirstEnergy Corp.	14,857.0	7.3%	13,696.9	7.7%

Table 18 Offered and cleared capacity by LDA, resource type, and season type: 2021/2022 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	170,841.5	53.5	354.8	149,615.6	27.2	354.8
RTO	DR	11,094.6	399.4	0.0	10,673.5	228.0	0.0
RTO	EE	2,649.0	154.2	0.0	2,622.7	105.5	0.0
EMAAC	GEN	29,931.3	2.9	0.5	27,377.9	0.9	0.5
EMAAC	DR	1,320.9	68.7	0.0	1,315.8	31.8	0.0
EMAAC	EE	605.7	21.5	0.0	593.8	11.7	0.0
PSEG	GEN	5,300.5	1.2	0.5	4,727.9	0.0	0.5
PSEG	DR	408.3	7.6	0.0	407.9	0.0	0.0
PSEG	EE	241.8	8.8	0.0	230.8	4.7	0.0
ATSI	GEN	10,663.6	0.0	0.0	6,723.0	0.0	0.0
ATSI	DR	1,221.2	0.0	0.0	1,142.4	0.0	0.0
ATSI	EE	141.9	5.7	0.0	141.9	3.2	0.0
ComEd	GEN	24,790.1	0.0	136.1	19,589.8	0.0	136.1
ComEd	DR	1,906.0	86.8	0.0	1,837.3	80.9	0.0
ComEd	EE	669.3	59.6	0.0	656.5	57.5	0.0
BGE	GEN	2,989.5	0.0	0.0	1,639.3	0.0	0.0
BGE	DR	216.8	76.9	0.0	194.8	42.4	0.0
BGE	EE	103.6	0.7	0.0	103.6	0.4	0.0

Table 19 Weighted average sell offer prices by LDA, resource type, and season type: 2021/2022 RPM Base Residual Auction

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$53.21	$5.03	$62.11
RTO	DR	$39.15	$9.55	
RTO	EE	$40.51	$3.54	
EMAAC	GEN	$56.82	$58.77	$60.00
EMAAC	DR	$44.27	$12.25	
EMAAC	EE	$72.73	$1.50	
PSEG	GEN	$83.40	$139.58	$60.00
PSEG	DR	$40.45	$70.23	
PSEG	EE	$91.49	$3.69	
ATSI	GEN	$107.34		
ATSI	DR	$42.79		
ATSI	EE	$2.54	$0.00	
ComEd	GEN	$80.40		$32.14
ComEd	DR	$43.68	$2.83	
ComEd	EE	$17.44	$0.00	
BGE	GEN	$157.57		
BGE	DR	$52.06	$0.00	
BGE	EE	$0.14	$0.00	

Table 20 Offered capacity by resource type, season type and price range as percent of net CONE times B: 2021/2022 RPM Base Residual Auction[139]

	Offered UCAP (MW)								
	Annual			Summer			Winter		
Resource Type	0 Percent	0 to 50 Percent	50 to >100 Percent	0 Percent	0 to 50 Percent	50 to >100 Percent	0 Percent	0 to 50 Percent	50 to >100 Percent
GEN	17,981.2	123,381.1	29,479.2	49.4	3.2	1.0	112.8	167.5	74.5
DR	530.3	9,792.0	772.3	350.6	48.8	0.0	0.0	0.0	0.0
EE	1,192.1	1,239.3	217.6	146.6	7.3	0.3	0.0	0.0	0.0

139 Data aggregated based on PJM confidentiality rules.

Table 21 Cleared MW by zone and resource type/fuel source: 2021/2022 RPM Base Residual Auction[140]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	83.4	40.6	453.2	1,049.3	0.0	0.0	22.9	12.3	0.0	0.0	1,661.7
AEP	1,680.4	164.8	5,032.2	9,496.9	52.3	93.0	0.0	0.0	43.3	247.8	16,810.7
AP	1,019.4	54.2	4,859.4	3,943.7	123.8	0.0	0.0	8.5	0.0	127.1	10,136.1
ATSI	1,142.4	145.1	2,103.8	4,205.5	0.0	0.0	413.7	0.0	0.0	0.0	8,010.5
BGE	237.2	104.0	1,158.7	227.5	0.0	1,687.3	198.1	0.0	55.0	0.0	3,667.8
ComEd	1,918.2	714.0	4,850.9	9,024.8	0.0	5,164.7	210.8	0.0	0.0	474.7	22,358.1
DAY	227.7	59.5	0.0	1,317.3	0.0	0.0	32.9	0.0	0.0	0.0	1,637.4
DEOK	201.8	89.1	1,721.8	584.9	109.0	0.0	39.5	0.0	0.0	0.0	2,746.1
DLCO	135.4	27.6	508.5	199.7	0.0	0.0	9.7	0.0	0.0	0.0	880.9
Dominion	1,136.1	559.2	3,774.0	12,674.1	3,115.4	3,523.3	992.7	348.0	153.4	67.5	26,343.7
DPL	233.8	47.1	396.5	4,056.1	0.0	0.0	644.6	90.5	0.0	0.0	5,468.6
EKPC	159.4	0.0	1,648.1	1,233.3	131.2	0.0	0.0	0.0	0.0	0.0	3,172.0
External	0.0	0.0	2,981.2	338.8	633.4	98.4	0.0	0.0	0.0	0.0	4,051.8
JCPL	170.3	176.8	0.0	2,900.5	278.0	0.0	199.9	59.0	0.0	0.0	3,784.5
Met-Ed	360.4	21.4	113.5	2,497.3	16.0	0.0	282.9	0.0	50.1	0.0	3,341.6
PECO	446.4	98.0	0.0	4,145.2	597.0	4,430.6	787.5	0.0	98.3	0.0	10,603.0
PENELEC	364.5	17.5	5,993.1	2,122.4	539.7	0.0	52.9	0.0	40.4	93.1	9,223.6
Pepco	286.2	98.9	2,297.3	3,548.3	0.0	0.0	268.9	0.0	46.5	0.0	6,546.1
PPL	684.7	67.6	3,301.4	7,837.0	625.7	2,491.1	294.7	7.6	8.5	50.3	15,368.6
PSEG	407.9	235.5	0.0	4,544.1	3.0	2,429.5	0.0	17.3	164.0	0.0	7,801.3
RECO	5.8	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.4
Total	10,901.5	2,728.2	41,193.6	75,946.7	6,224.5	19,917.9	4,451.7	543.2	659.5	1,060.5	163,627.3

140 Resources that operate at or above 500 kV may be physically located in a zonal LDA but are modeled in the parent LDA. For example, 2,917.0 MW of the 8,016.6 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 22 Uncleared generation offers by technology type and age: 2021/2022 RPM Base Residual Auction[141] [142]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal Fired	1,684.9	4,321.9	6,006.8
Combined cycle	1,310.1	0.0	1,310.1
Combustion turbine	636.2	219.5	855.7
Nuclear	6,821.4	3,821.3	10,642.7
Oil or gas steam	0.0	1,801.9	1,801.9
Other	143.7	491.4	635.1
Total	10,596.3	10,656.0	21,252.3

Table 23 Uncleared generation resources in multiple auctions[143] [144]

	2021/2022		2020/2021 Results for Same Set of Resources		2019/2020 Results for Same Set of Resources	
Technology	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources
Coal Fired	6,006.8	64	4,370.0	38	2,300.3	27
Combined cycle	1,310.1	48	751.9	10	229.9	8
Combustion turbine	855.7	83	827.7	59	496.9	31
Other	13,079.7	74	1,944.6	30	1,684.4	13
Total	21,252.3	269	7,894.2	137	4,711.5	79

141 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2021/2022 BRA, waste coal resources are included in the coal fired category.

142 Data aggregated based on PJM confidentiality rules.

143 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2021/2022 BRA, waste coal resources are included in the coal fired category.

144 Data aggregated based on PJM confidentiality rules.

Table 24 PJM LDA CETL and CETO values: 2020/2021 and 2021/2022 RPM Base Residual Auctions

	2020/2021			2021/2022			Change			
							CETO		CETL	
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	(7,000.0)	4,218.0	(60%)	(8,870.0)	4,019.0	(45%)	(1,870.0)	27%	(199.0)	(5%)
EMAAC	3,650.0	8,800.0	241%	2,500.0	9,000.0	360%	(1,150.0)	(32%)	200.0	2%
SWMAAC	2,900.0	9,802.0	338%	2,870.0	9,082.0	316%	(30.0)	(1%)	(720.0)	(7%)
PSEG	5,900.0	8,001.0	136%	5,620.0	6,902.0	123%	(280.0)	(5%)	(1,099.0)	(14%)
PSEG North	2,620.0	4,264.0	163%	2,410.0	3,180.0	132%	(210.0)	(8%)	(1,084.0)	(25%)
DPL South	1,230.0	1,872.0	152%	1,080.0	1,624.0	150%	(150.0)	(12%)	(248.0)	(13%)
Pepco	1,540.0	7,625.0	495%	1,550.0	6,915.0	446%	10.0	1%	(710.0)	(9%)
ATSI	4,660.0	9,889.0	212%	6,020.0	8,439.0	140%	1,360.0	29%	(1,450.0)	(15%)
ATSI Cleveland	3,540.0	5,605.0	158%	4,100.0	5,256.0	128%	560.0	16%	(349.0)	(6%)
ComEd	640.0	4,064.0	635%	(640.0)	5,574.0	(871%)	(1,280.0)	(200%)	1,510.0	37%
BGE	4,410.0	6,244.0	142%	4,470.0	6,005.0	134%	60.0	1%	(239.0)	(4%)
PPL	(1,010.0)	7,084.0	(701%)	(850.0)	6,609.0	(778%)	160.0	(16%)	(475.0)	(7%)
DAY	2,550.0	3,401.0	133%	2,480.0	3,502.0	141%	(70.0)	(3%)	101.0	3%
DEOK	3,650.0	5,072.0	139%	3,110.0	4,959.0	159%	(540.0)	(15%)	(113.0)	(2%)

Table 25 Changes to PJM LDA CETL values

LDA	CETL Values 2020/2021 BRA	Proposed CETL Values (August 2017)	CETL Values 2021/2022 BRA
MAAC	4,218	3,118	4,019
EMAAC	8,800	8,300	9,000
SWMAAC	9,802		9,082
PSEG	8,001	6,474	6,902
PSEG North	4,264	2,955	3,180
DPL South	1,872		1,624
PEPCO	7,625		6,915
ATSI	9,889		8,439
ATSI-Cleveland	5,605		5,256
ComEd	4,064		5,574
BGE	6,244		6,005
PPL	7,084		6,609
DAY	3,401		3,502
DEOK	5,072		4,959

Table 26 Impact of ComEd CETL change: 2021/2022 RPM Base Residual Auction

Scenario 1

		Actual Auction Results		ComEd CETL	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$112.75	163,793.4
	Summer	$140.00	715.5	$112.75	715.5
	Winter	$140.00	715.5	$112.75	715.5
RTO Total			163,627.3		164,508.9
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	8.7
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5
	Summer	$165.73	88.0	$165.73	20.4
	Winter	$165.73	1.0	$165.73	1.0
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.7
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$180.50	1,959.6
	Summer	$200.30	85.0	$180.50	153.1
	Winter	$200.30	0.0	$180.50	0.0
BGE Total			1,937.7		1,959.6
ComEd	Annual	$195.55	22,083.6	$189.10	23,630.8
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		23,905.3
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	44.7
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Table 27 Impact of PSEG CETL adjustment: 2021/2022 RPM Base Residual Auction Scenario 2

		Actual Auction Results		PSEG CETL Adjustment	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$140.00	162,911.8
	Summer	$140.00	715.5	$140.00	715.5
	Winter	$140.00	715.5	$140.00	715.5
RTO Total			163,627.3		163,627.3
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	6.3
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.47	29,289.5
	Summer	$165.73	88.0	$165.47	88.2
	Winter	$165.73	1.0	$165.47	1.0
EMAAC Total			29,288.5		29,290.5
PSEG	Annual	$204.29	5,366.6	$206.58	5,561.2
	Summer	$204.29	9.3	$206.58	9.3
	Winter	$204.29	1.0	$206.58	1.0
PSEG Total			5,367.6		5,562.2
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	85.0
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$195.55	22,083.6
	Summer	$195.55	274.5	$195.55	274.5
	Winter	$195.55	274.5	$195.55	274.5
ComEd Total			22,358.1		22,358.1

Table 28 Impact of load forecast reduction: 2021/2022 RPM Base Residual Auction Scenario 3

		Actual Auction Results		Reduce Load Forecast by 5.8 percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$80.00	154,726.3
	Summer	$140.00	715.5	$80.00	623.5
	Winter	$140.00	715.5	$80.00	623.5
RTO Total			163,627.3		155,349.8
ATSI	Annual	$171.33	8,007.3	$226.40	6,889.1
	Summer	$171.33	6.3	$226.40	5.4
	Winter	$171.33	0.0	$226.40	0.0
ATSI Total			8,007.3		6,889.1
EMAAC	Annual	$165.73	29,287.5	$139.46	27,309.0
	Summer	$165.73	88.0	$139.46	10.3
	Winter	$165.73	1.0	$139.46	1.0
EMAAC Total			29,288.5		27,310.0
PSEG	Annual	$204.29	5,366.6	$160.00	4,775.5
	Summer	$204.29	9.3	$160.00	5.3
	Winter	$204.29	1.0	$160.00	1.0
PSEG Total			5,367.6		4,776.5
BGE	Annual	$200.30	1,937.7	$178.77	1,492.6
	Summer	$200.30	85.0	$178.77	110.8
	Winter	$200.30	0.0	$178.77	0.0
BGE Total			1,937.7		1,492.6
ComEd	Annual	$195.55	22,083.6	$198.48	20,498.2
	Summer	$195.55	274.5	$198.48	274.5
	Winter	$195.55	274.5	$198.48	274.5
ComEd Total			22,358.1		20,772.7
DEOK	Annual	$140.00	2,733.3	$107.23	2,284.4
	Summer	$140.00	25.4	$107.23	0.0
	Winter	$140.00	0.0	$107.23	0.0
DEOK Total			2,733.3		2,284.4

Table 29 Impact of one percent rightward shift in the VRR curve: 2021/2022 RPM Base Residual Auction

Scenario 4

		Actual Auction Results		Impact of 1.0 percent VRR shift	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$129.43	161,931.0
	Summer	$140.00	715.5	$129.43	715.5
	Winter	$140.00	715.5	$129.43	715.5
RTO Total			163,627.3		162,646.5
ATSI	Annual	$171.33	8,007.3	$145.00	7,963.5
	Summer	$171.33	6.3	$145.00	6.3
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,963.5
EMAAC	Annual	$165.73	29,287.5	$165.00	28,982.4
	Summer	$165.73	88.0	$165.00	88.2
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,983.4
PSEG	Annual	$204.29	5,366.6	$194.47	5,290.5
	Summer	$204.29	9.3	$194.47	9.3
	Winter	$204.29	1.0	$194.47	1.0
PSEG Total			5,367.6		5,291.5
BGE	Annual	$200.30	1,937.7	$178.77	1,895.2
	Summer	$200.30	85.0	$178.77	85.0
	Winter	$200.30	0.0	$178.77	0.0
BGE Total			1,937.7		1,895.2
ComEd	Annual	$195.55	22,083.6	$184.04	21,917.4
	Summer	$195.55	274.5	$184.04	274.5
	Winter	$195.55	274.5	$184.04	274.5
ComEd Total			22,358.1		22,191.9

Table 30 Offers greater than $35.00 per MW-day in total RTO supply curve: 2021/2022 RPM Base Residual Auction[145] [146]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	23,157.3	30.8%
Nuclear	14,987.2	19.9%
Combined cycle	13,586.8	18.1%
Combustion turbine	8,508.6	11.3%
Oil or gas steam	7,297.5	9.7%
Demand Resource	3,824.8	5.1%
Hydro	1,890.8	2.5%
Energy Efficiency Resource	1,123.1	1.5%
Wind	419.4	0.6%
Other generation	235.7	0.3%
Solar	202.7	0.3%
Total	75,234.0	100.0%

145 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2021/2022 BRA, waste coal resources are included in the coal fired category.

146 Data aggregated based on PJM confidentiality rules.

Table 31 DR and EE statistics by LDA: 2020/2021 and 2021/2022 RPM Base Residual Auctions

		2020/2021 BRA			2021/2022 BRA			Change					
								Offered ICAP		Offered UCAP		Cleared UCAP	
LDA	Resource Type	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	MW	Percent	MW	Percent	MW	Percent
RTO	DR	8,373.2	9,113.0	7,677.1	10,551.3	11,494.0	10,901.5	2,178.1	26.0%	2,380.9	26.1%	3,224.4	42.0%
RTO	EE	1,877.7	2,042.4	1,659.2	2,574.6	2,803.2	2,728.2	696.9	37.1%	760.7	37.2%	1,069.0	64.4%
MAAC	DR	2,807.8	3,054.4	2,606.4	3,213.4	3,498.6	3,280.7	405.6	14.4%	444.2	14.5%	674.2	25.9%
MAAC	EE	590.0	641.0	526.9	871.6	948.2	914.8	281.6	47.7%	307.2	47.9%	387.9	73.6%
EMAAC	DR	1,097.5	1,193.3	1,085.7	1,276.1	1,389.6	1,347.6	178.6	16.3%	196.2	16.4%	261.9	24.1%
EMAAC	EE	289.5	314.0	288.7	576.5	627.2	605.5	287.0	99.1%	313.2	99.8%	316.8	109.7%
SWMAAC	DR	520.4	566.2	395.0	584.4	635.8	523.4	64.0	12.3%	69.6	12.3%	128.5	32.5%
SWMAAC	EE	199.1	216.8	179.8	189.2	206.1	202.9	(9.8)	(4.9%)	(10.7)	(4.9%)	23.1	12.8%
DPL South	DR	71.1	77.2	72.6	64.3	70.0	66.3	(6.8)	(9.5%)	(7.2)	(9.3%)	(6.3)	(8.7%)
DPL South	EE	7.9	8.6	8.6	13.5	14.5	13.6	5.6	70.9%	5.9	68.6%	5.0	58.1%
PSEG	DR	311.6	338.9	325.9	381.7	415.9	407.9	70.1	22.5%	76.9	22.7%	82.0	25.2%
PSEG	EE	94.5	102.5	92.8	230.0	250.6	235.5	135.5	143.4%	148.0	144.4%	142.7	153.7%
PSEG North	DR	132.9	144.3	141.4	178.5	194.5	188.6	45.7	34.4%	50.2	34.8%	47.2	33.4%
PSEG North	EE	18.9	20.4	17.9	70.3	76.6	71.6	51.5	272.7%	56.3	276.1%	53.7	300.1%
Pepco	DR	235.0	255.7	183.9	314.3	342.1	286.2	79.3	33.7%	86.5	33.8%	102.3	55.6%
Pepco	EE	73.3	79.7	60.8	93.5	101.8	98.9	20.2	27.6%	22.1	27.8%	38.1	62.7%
ATSI	DR	735.8	800.6	688.6	1,120.8	1,221.2	1,142.4	385.0	52.3%	420.6	52.5%	453.8	65.9%
ATSI	EE	45.9	49.8	32.5	135.5	147.6	145.1	89.6	195.0%	97.9	196.6%	112.6	346.3%
ATSI Cleveland	DR	184.6	200.9	168.9	263.6	287.2	272.8	79.0	42.8%	86.3	42.9%	103.9	61.5%
ATSI Cleveland	EE	0.4	0.4	0.4	33.2	36.2	36.2	32.8	8,187.6%	35.8	8,937.6%	35.8	8,937.6%
ComEd	DR	1,485.2	1,617.4	1,469.8	1,828.7	1,992.8	1,918.2	343.5	23.1%	375.4	23.2%	448.5	30.5%
ComEd	EE	665.6	724.7	671.2	668.9	728.9	714.0	3.3	0.5%	4.2	0.6%	42.8	6.4%
BGE	DR	285.4	310.5	211.0	270.1	293.7	237.2	(15.3)	(5.4%)	(16.8)	(5.4%)	26.2	12.4%
BGE	EE	125.8	137.1	119.1	95.8	104.3	104.0	(30.0)	(23.9%)	(32.8)	(23.9%)	(15.0)	(12.6%)
PPL	DR	604.6	658.4	579.9	672.9	732.8	684.7	68.3	11.3%	74.4	11.3%	104.8	18.1%
PPL	EE	49.8	54.2	34.0	66.8	72.6	67.6	17.0	34.1%	18.4	33.9%	33.6	99.1%
DAY	DR	189.2	205.8	164.5	215.9	235.0	227.7	26.7	14.1%	29.2	14.2%	63.2	38.4%
DAY	EE	43.7	47.4	32.9	62.0	67.2	59.5	18.4	42.1%	19.9	41.9%	26.6	81.0%
DEOK	DR	157.0	170.3	145.7	196.8	214.0	201.8	39.8	25.3%	43.7	25.7%	56.1	38.5%
DEOK	EE	61.1	66.4	65.6	82.2	89.6	89.1	21.1	34.6%	23.2	35.0%	23.5	35.9%

Table 32 Impact of demand side products: 2021/2022 RPM Base Residual Auction Scenario 5

		Actual Auction Results		No Offers for DR or EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.11	158,019.2
	Summer	$140.00	715.5	$189.11	106.2
	Winter	$140.00	715.5	$189.11	106.2
RTO Total			163,627.3		158,125.4
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$189.11	28,481.8
	Summer	$165.73	88.0	$189.11	5.7
	Winter	$165.73	1.0	$189.11	0.0
EMAAC Total			29,288.5		28,481.8
PSEG	Annual	$204.29	5,366.6	$207.08	4,983.6
	Summer	$204.29	9.3	$207.08	2.4
	Winter	$204.29	1.0	$207.08	0.0
PSEG Total			5,367.6		4,983.6
BGE	Annual	$200.30	1,937.7	$189.11	2,839.3
	Summer	$200.30	85.0	$189.11	0.0
	Winter	$200.30	0.0	$189.11	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.11	21,719.1
	Summer	$195.55	274.5	$189.11	0.0
	Winter	$195.55	274.5	$189.11	96.8
ComEd Total			22,358.1		21,719.1

Table 33 Impact of EE resources: 2021/2022 RPM Base Residual Auction

Scenario 6

		Actual Auction Results		No Offers for EE and EE Add Back Removed	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$127.28	159,410.3
	Summer	$140.00	715.5	$127.28	715.5
	Winter	$140.00	715.5	$127.28	715.5
RTO Total			163,627.3		160,125.8
ATSI	Annual	$171.33	8,007.3	$145.00	7,843.6
	Summer	$171.33	6.3	$145.00	0.0
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,843.6
EMAAC	Annual	$165.73	29,287.5	$165.00	28,360.8
	Summer	$165.73	88.0	$165.00	117.3
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,361.8
PSEG	Annual	$204.29	5,366.6	$179.16	5,048.6
	Summer	$204.29	9.3	$179.16	1.0
	Winter	$204.29	1.0	$179.16	1.0
PSEG Total			5,367.6		5,049.6
BGE	Annual	$200.30	1,937.7	$191.18	1,834.1
	Summer	$200.30	85.0	$191.18	152.6
	Winter	$200.30	0.0	$191.18	0.0
BGE Total			1,937.7		1,834.1
ComEd	Annual	$195.55	22,083.6	$189.10	21,376.0
	Summer	$195.55	274.5	$189.10	172.2
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		21,548.2
DEOK	Annual	$140.00	2,733.3	$128.47	2,512.9
	Summer	$140.00	25.4	$128.47	43.6
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,512.9

Table 34 Impact of annual demand side products: 2021/2022 RPM Base Residual Auction

Scenario 7

		Actual Auction Results		No Offers for Annual DR and Annual EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.10	157,682.7
	Summer	$140.00	715.5	$189.10	715.5
	Winter	$140.00	715.5	$189.10	715.5
RTO Total			163,627.3		158,398.2
ATSI	Annual	$171.33	8,007.3	$216.83	7,614.6
	Summer	$171.33	6.3	$216.83	6.3
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,614.6
EMAAC	Annual	$165.73	29,287.5	$189.10	28,482.7
	Summer	$165.73	88.0	$189.10	86.9
	Winter	$165.73	1.0	$189.10	1.0
EMAAC Total			29,288.5		28,483.7
PSEG	Annual	$204.29	5,366.6	$207.08	4,984.5
	Summer	$204.29	9.3	$207.08	7.8
	Winter	$204.29	1.0	$207.08	1.0
PSEG Total			5,367.6		4,985.5
BGE	Annual	$200.30	1,937.7	$189.10	2,839.3
	Summer	$200.30	85.0	$189.10	85.3
	Winter	$200.30	0.0	$189.10	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.10	21,362.7
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		21,637.2

Table 35 Impact of seasonal demand side products: 2021/2022 RPM Base Residual Auction

Scenario 8

		Actual Auction Results		No Offers for Seasonal DR and Seasonal EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$140.00	163,116.3
	Summer	$140.00	715.5	$140.00	106.2
	Winter	$140.00	715.5	$140.00	106.2
RTO Total			163,627.3		163,222.5
ATSI	Annual	$171.33	8,007.3	$166.26	8,005.8
	Summer	$171.33	6.3	$166.26	0.0
	Winter	$171.33	0.0	$166.26	0.0
ATSI Total			8,007.3		8,005.8
EMAAC	Annual	$165.73	29,287.5	$165.47	29,228.8
	Summer	$165.73	88.0	$165.47	5.7
	Winter	$165.73	1.0	$165.47	0.5
EMAAC Total			29,288.5		29,229.3
PSEG	Annual	$204.29	5,366.6	$198.45	5,355.5
	Summer	$204.29	9.3	$198.45	2.4
	Winter	$204.29	1.0	$198.45	0.5
PSEG Total			5,367.6		5,356.0
BGE	Annual	$200.30	1,937.7	$198.69	1,937.7
	Summer	$200.30	85.0	$198.69	0.0
	Winter	$200.30	0.0	$198.69	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$190.79	22,255.9
	Summer	$195.55	274.5	$190.79	0.0
	Winter	$195.55	274.5	$190.79	94.9
ComEd Total			22,358.1		22,255.9

Table 36 Impact of seasonal products: 2021/2022 RPM Base Residual Auction Scenario 9

		Actual Auction Results		Annual Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$142.49	163,142.0
	Summer	$140.00	715.5	$142.49	0.0
	Winter	$140.00	715.5	$142.49	0.0
RTO Total			163,627.3		163,142.0
ATSI	Annual	$171.33	8,007.3	$166.26	8,005.8
	Summer	$171.33	6.3	$166.26	0.0
	Winter	$171.33	0.0	$166.26	0.0
ATSI Total			8,007.3		8,005.8
EMAAC	Annual	$165.73	29,287.5	$165.47	29,229.3
	Summer	$165.73	88.0	$165.47	0.0
	Winter	$165.73	1.0	$165.47	0.0
EMAAC Total			29,288.5		29,229.3
PSEG	Annual	$204.29	5,366.6	$198.66	5,355.5
	Summer	$204.29	9.3	$198.66	0.0
	Winter	$204.29	1.0	$198.66	0.0
PSEG Total			5,367.6		5,355.5
BGE	Annual	$200.30	1,937.7	$198.69	1,937.7
	Summer	$200.30	85.0	$198.69	0.0
	Winter	$200.30	0.0	$198.69	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$190.79	22,255.9
	Summer	$195.55	274.5	$190.79	0.0
	Winter	$195.55	274.5	$190.79	0.0
ComEd Total			22,358.1		22,255.9

Table 37 Impact of demand side and seasonal products: 2021/2022 RPM Base Residual Auction

Scenario 10

		Actual Auction Results		Annual Generation Offers Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$189.12	158,125.1
	Summer	$140.00	715.5	$189.12	0.0
	Winter	$140.00	715.5	$189.12	0.0
RTO Total			163,627.3		158,125.1
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$189.12	28,481.8
	Summer	$165.73	88.0	$189.12	0.0
	Winter	$165.73	1.0	$189.12	0.0
EMAAC Total			29,288.5		28,481.8
PSEG	Annual	$204.29	5,366.6	$207.08	4,983.6
	Summer	$204.29	9.3	$207.08	0.0
	Winter	$204.29	1.0	$207.08	0.0
PSEG Total			5,367.6		4,983.6
BGE	Annual	$200.30	1,937.7	$189.12	2,839.3
	Summer	$200.30	85.0	$189.12	0.0
	Winter	$200.30	0.0	$189.12	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$189.12	21,825.0
	Summer	$195.55	274.5	$189.12	0.0
	Winter	$195.55	274.5	$189.12	0.0
ComEd Total			22,358.1		21,825.0

Table 38 Impact of winter resources: 2021/2022 RPM Base Residual Auction

Scenario 11

		Actual Auction Results		Reduce Winter Offers by 50 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$141.31	163,226.0
	Summer	$140.00	715.5	$141.31	358.9
	Winter	$140.00	715.5	$141.31	358.9
RTO Total			163,627.3		163,584.9
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	3.0
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,288.0
	Summer	$165.73	88.0	$165.73	39.9
	Winter	$165.73	1.0	$165.73	0.5
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.50	5,366.6
	Summer	$204.29	9.3	$204.50	1.8
	Winter	$204.29	1.0	$204.50	0.5
PSEG Total			5,367.6		5,367.1
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	41.1
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$184.04	22,279.7
	Summer	$195.55	274.5	$184.04	137.7
	Winter	$195.55	274.5	$184.04	137.7
ComEd Total			22,358.1		22,417.4

Table 39 Impact of seasonal matching across LDAs: 2021/2022 RPM Base Residual Auction

Scenario 12

		Actual Auction Results		No Matched Seasonal Offers Across LDAs	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$140.00	162,911.8
	Summer	$140.00	715.5	$140.00	715.5
	Winter	$140.00	715.5	$140.00	715.5
RTO Total			163,627.3		163,627.3
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	6.3
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5
	Summer	$165.73	88.0	$165.73	88.0
	Winter	$165.73	1.0	$165.73	1.0
EMAAC Total			29,288.5		29,288.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	85.0
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$195.55	22,083.6
	Summer	$195.55	274.5	$195.55	274.5
	Winter	$195.55	274.5	$195.55	274.5
ComEd Total			22,358.1		22,358.1

Table 40 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

Table 41 Impact of capacity imports: 2021/2022 RPM Base Residual Auction

Scenario 13, Scenario 14, Scenario 15, Scenario 16

		Actual Auction Results		Reduce Imports 25 percent		Reduce Imports 50 percent		Reduce Imports 75 percent		Reduce Imports 100 percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$149.47	162,605.3	$160.80	162,238.8	$170.00	161,941.1	$172.64	161,855.6
	Summer	$140.00	715.5	$149.47	715.5	$160.80	715.5	$170.00	715.5	$172.64	715.5
	Winter	$140.00	715.5	$149.47	715.5	$160.80	715.5	$170.00	715.5	$172.64	715.5
RTO Total			163,627.3		163,320.8		162,954.3		162,656.6		162,571.1
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3	$171.33	8,007.3	$171.33	8,007.3	$172.64	8,007.3
	Summer	$171.33	6.3	$171.33	6.3	$171.33	6.3	$171.33	6.4	$172.64	6.3
	Winter	$171.33	0.0	$171.33	0.0	$171.33	0.0	$171.33	0.0	$172.64	0.0
ATSI Total			8,007.3		8,007.3		8,007.3		8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$165.73	29,287.5	$165.73	29,287.5	$170.00	29,317.8	$172.64	29,393.5
	Summer	$165.73	88.0	$165.73	87.9	$165.73	87.9	$170.00	83.6	$172.64	87.9
	Winter	$165.73	1.0	$165.73	1.0	$165.73	1.0	$170.00	1.0	$172.64	1.0
EMAAC Total			29,288.5		29,288.5		29,288.5		29,318.8		29,394.5
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3	$204.29	9.3	$204.29	3.6	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0	$204.29	1.0	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6		5,367.6		5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	84.6	$200.30	84.6	$200.30	86.1	$200.30	84.6
	Winter	$200.30	0.0	$200.30	0.0	$200.30	0.0	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7		1,937.7		1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$189.01	22,117.3	$189.01	22,117.3	$189.01	22,117.3	$184.05	22,142.8
	Summer	$195.55	274.5	$189.01	274.5	$189.01	274.5	$189.01	274.5	$184.05	274.5
	Winter	$195.55	274.5	$189.01	274.5	$189.01	274.5	$189.01	274.5	$184.05	274.5
ComEd Total			22,358.1		22,391.8		22,391.8		22,391.8		22,417.3

Table 42 Impact of demand side and seasonal products, and capacity imports: 2021/2022 RPM Base Residual Auction

Scenario 17

		Actual Auction Results		Annual Generation Only, No DR and Reduce Imports 100 pct	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$208.16	157,509.1
	Summer	$140.00	715.5	$208.16	0.0
	Winter	$140.00	715.5	$208.16	0.0
RTO Total			163,627.3		157,509.1
ATSI	Annual	$171.33	8,007.3	$216.83	7,595.6
	Summer	$171.33	6.3	$216.83	0.0
	Winter	$171.33	0.0	$216.83	0.0
ATSI Total			8,007.3		7,595.6
EMAAC	Annual	$165.73	29,287.5	$208.16	29,638.6
	Summer	$165.73	88.0	$208.16	0.0
	Winter	$165.73	1.0	$208.16	0.0
EMAAC Total			29,288.5		29,638.6
PSEG	Annual	$204.29	5,366.6	$208.16	5,127.4
	Summer	$204.29	9.3	$208.16	0.0
	Winter	$204.29	1.0	$208.16	0.0
PSEG Total			5,367.6		5,127.4
BGE	Annual	$200.30	1,937.7	$208.16	2,839.3
	Summer	$200.30	85.0	$208.16	0.0
	Winter	$200.30	0.0	$208.16	0.0
BGE Total			1,937.7		2,839.3
ComEd	Annual	$195.55	22,083.6	$208.16	22,707.1
	Summer	$195.55	274.5	$208.16	0.0
	Winter	$195.55	274.5	$208.16	0.0
ComEd Total			22,358.1		22,707.1

Table 43 Impact of inconsistency between EE cleared MW and EE add back MW: 2021/2022 RPM Base Residual Auction

Scenario 18

		Actual Auction Results		EE Add Back Equal to Cleared EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$132.68	162,087.9
	Summer	$140.00	715.5	$132.68	715.5
	Winter	$140.00	715.5	$132.68	715.5
RTO Total			163,627.3		162,803.4
ATSI	Annual	$171.33	8,007.3	$145.00	7,985.5
	Summer	$171.33	6.3	$145.00	11.4
	Winter	$171.33	0.0	$145.00	0.0
ATSI Total			8,007.3		7,985.5
EMAAC	Annual	$165.73	29,287.5	$165.00	28,944.5
	Summer	$165.73	88.0	$165.00	22.6
	Winter	$165.73	1.0	$165.00	1.0
EMAAC Total			29,288.5		28,945.5
PSEG	Annual	$204.29	5,366.6	$179.58	5,268.3
	Summer	$204.29	9.3	$179.58	6.7
	Winter	$204.29	1.0	$179.58	1.0
PSEG Total			5,367.6		5,269.3
BGE	Annual	$200.30	1,937.7	$191.18	1,937.7
	Summer	$200.30	85.0	$191.18	153.1
	Winter	$200.30	0.0	$191.18	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$189.10	22,038.0
	Summer	$195.55	274.5	$189.10	274.5
	Winter	$195.55	274.5	$189.10	274.5
ComEd Total			22,358.1		22,312.5

Table 44 Impact of price responsive demand (PRD): 2021/2022 RPM Base Residual Auction

Scenario 19

		Actual Auction Results		No PRD Offers	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$142.60	163,383.5
	Summer	$140.00	715.5	$142.60	715.5
	Winter	$140.00	715.5	$142.60	715.5
RTO Total			163,627.3		164,099.0
ATSI	Annual	$171.33	8,007.3	$171.33	8,007.3
	Summer	$171.33	6.3	$171.33	5.4
	Winter	$171.33	0.0	$171.33	0.0
ATSI Total			8,007.3		8,007.3
EMAAC	Annual	$165.73	29,287.5	$172.33	29,317.8
	Summer	$165.73	88.0	$172.33	10.4
	Winter	$165.73	1.0	$172.33	1.0
EMAAC Total			29,288.5		29,318.8
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	3.2
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$180.50	2,221.2
	Summer	$200.30	85.0	$180.50	152.6
	Winter	$200.30	0.0	$180.50	0.0
BGE Total			1,937.7		2,221.2
ComEd	Annual	$195.55	22,083.6	$189.01	22,117.3
	Summer	$195.55	274.5	$189.01	274.5
	Winter	$195.55	274.5	$189.01	274.5
ComEd Total			22,358.1		22,391.8

Table 45 Peak load forecast history[147] [148]

	DY	BRA	First IA	Second IA	Third IA	Actual DY Peak Load	Percent Change BRA to 1st	Percent Change BRA to 2nd	Percent Change BRA to 3rd	Percent Change BRA to Actual
Forecast Peak Load	2019/2020	157,188.5	154,510.0				(1.7%)			
Installed Reverve Margin		16.5%	16.60%				0.6%			
Pool Wide EFORd		6.60%	6.59%				(0.2%)			
Forecast Pool Requirement		1.0881	1.0892				0.1%			
Reliability Requirement		171,036.8	168,292.3				(1.6%)			
Forecast Peak Load	2018/2019	161,418.4	156,141.1	154,179.9	152,407.9		(3.3%)	(4.5%)	(5.6%)	
Installed Reverve Margin		15.7%	16.50%	16.70%	16.1%		5.1%	6.4%	2.5%	
Pool Wide EFORd		6.35%	6.58%	6.59%	6.07%		3.6%	3.8%	(4.4%)	
Forecast Pool Requirement		1.0835	1.0883	1.0901	1.0905		0.4%	0.6%	0.6%	
Reliability Requirement		174,896.8	169,928.4	168,071.5	166,200.8		(2.8%)	(3.9%)	(5.0%)	
Forecast Peak Load	2017/2018	164,478.8	160,092.2	154,377.3	153,230.1	145,635.9	(2.7%)	(6.1%)	(6.8%)	(11.5%)
Installed Reverve Margin		15.7%	15.70%	16.50%	16.60%		0.0%	5.1%	5.7%	
Pool Wide EFORd		5.65%	5.70%	5.93%	5.94%		0.9%	5.0%	5.1%	
Forecast Pool Requirement		1.0916	1.0911	1.0959	1.0967		(0.0%)	0.4%	0.5%	
Reliability Requirement		179,545.1	174,676.6	169,182.1	168,047.5		(2.7%)	(5.8%)	(6.4%)	
Forecast Peak Load	2016/2017	165,412.0	162,749.7	158,193.0	152,356.6	152,176.9	(1.6%)	(4.4%)	(7.9%)	(8.0%)
Installed Reverve Margin		15.6%	15.70%	15.50%	16.40%		0.6%	(0.6%)	5.1%	
Pool Wide EFORd		5.69%	5.64%	5.66%	5.91%		(0.9%)	(0.5%)	3.9%	
Forecast Pool Requirement		1.0902	1.0917	1.0896	1.0952		0.1%	(0.1%)	0.5%	
Reliability Requirement		180,332.2	177,673.8	172,367.1	166,860.9		(1.5%)	(4.4%)	(7.5%)	
Forecast Peak Load	2015/2016	163,168.0	160,325.0	160,538.2	155,823.3	143,696.7	(1.7%)	(1.6%)	(4.5%)	(11.9%)
Installed Reverve Margin		15.4%	15.30%	15.70%	15.60%		(0.6%)	1.9%	1.3%	
Pool Wide EFORd		5.90%	5.91%	5.62%	5.60%		0.2%	(4.7%)	(5.1%)	
Forecast Pool Requirement		1.0859	1.0849	1.092	1.0913		(0.1%)	0.6%	0.5%	
Reliability Requirement		177,184.1	173,936.6	175,307.7	170,050.0		(1.8%)	(1.1%)	(4.0%)	
Forecast Peak Load	2014/2015	164,757.6	159,845.0	156,863.0	157,562.8	143,114.9	(3.0%)	(4.8%)	(4.4%)	(13.1%)
Installed Reverve Margin		15.3%	15.40%	15.90%	16.20%		0.7%	3.9%	5.9%	
Pool Wide EFORd		6.25%	5.89%	6.05%	5.97%		(5.8%)	(3.2%)	(4.5%)	
Forecast Pool Requirement		1.0809	1.086	1.0889	1.0926		0.5%	0.7%	1.1%	
Reliability Requirement		178,086.5	173,591.7	170,808.1	172,153.1		(2.5%)	(4.1%)	(3.3%)	
Forecast Peak Load	2013/2014	160,634.0	156,749.0	150,828.0	148,451.0	157,508.5	(2.4%)	(6.1%)	(7.6%)	(1.9%)
Installed Reverve Margin		15.3%	15.30%	15.40%	15.90%		0.0%	0.7%	3.9%	
Pool Wide EFORd		6.30%	6.25%	5.90%	6.05%		(0.8%)	(6.3%)	(4.0%)	
Forecast Pool Requirement		1.0804	1.0809	1.0859	1.0889		0.0%	0.5%	0.8%	
Reliability Requirement		173,549.0	169,430.0	163,784.1	161,648.3		(2.4%)	(5.6%)	(6.9%)	

147 PJM made changes to the load forecast model in December 2015. See Revision 29 in PJM Manual 19 for details. The revised model was first used for the 2019/2020 BRA held in May 2016 and has been used to determine the forecast peak load in all subsequent RPM auctions. Auctions using the revised load forecast model consist of the following: 2017/2018 (Second IA, Third IA), 2018/2019 (First IA, Second IA, Third IA), 2019/2020 (BRA, First IA), 2020/2021 BRA, 2021/2022 BRA.

148 The data have not been adjusted to reflect the integration of the DEOK Control Zone (January 1, 2012) and the EKPC Control Zone (June 1, 2013). Forecasts and actual peak load for the 2013/2014, 2014/2015, and 2015/2016 Delivery Years are affected.

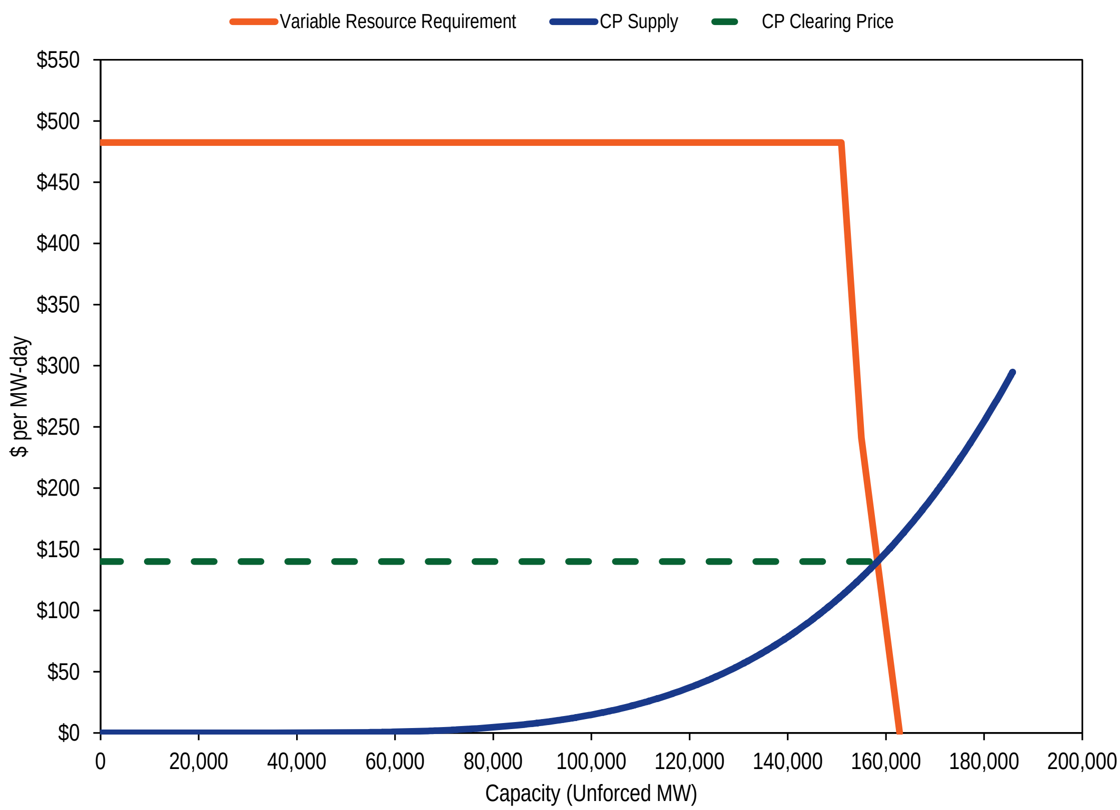
Table 46 Nuclear offers set to $0 per MW-day: 2021/2022 RPM Base Residual Auction Scenario 20

		Actual Auction Results		All Nuclear Offers at $0 per MW-day	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$71.48	165,256.7
	Summer	$140.00	715.5	$71.48	587.6
	Winter	$140.00	715.5	$71.48	587.6
RTO Total			163,627.3		165,844.3
ATSI	Annual	$171.33	8,007.3	$71.48	8,603.4
	Summer	$171.33	6.3	$71.48	6.2
	Winter	$171.33	0.0	$71.48	0.0
ATSI Total			8,007.3		8,603.4
EMAAC	Annual	$165.73	29,287.5	$125.94	29,597.6
	Summer	$165.73	88.0	$125.94	86.7
	Winter	$165.73	1.0	$125.94	1.0
EMAAC Total			29,288.5		29,598.6
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.2
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$200.30	1,937.7
	Summer	$200.30	85.0	$200.30	83.5
	Winter	$200.30	0.0	$200.30	0.0
BGE Total			1,937.7		1,937.7
ComEd	Annual	$195.55	22,083.6	$71.48	24,345.0
	Summer	$195.55	274.5	$71.48	154.4
	Winter	$195.55	274.5	$71.48	268.2
ComEd Total			22,358.1		24,499.4
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	24.9
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Table 47 Impact of noncompetitive offers: 2021/2022 RPM Base Residual Auction Scenario 21

		Actual Auction Results		Noncompetitive Offers capped at net ACR	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$140.00	162,911.8	$124.40	163,416.6
	Summer	$140.00	715.5	$124.40	715.5
	Winter	$140.00	715.5	$124.40	715.5
RTO Total			163,627.3		164,132.1
ATSI	Annual	$171.33	8,007.3	$169.65	8,013.1
	Summer	$171.33	6.3	$169.65	6.3
	Winter	$171.33	0.0	$169.65	0.0
ATSI Total			8,007.3		8,013.1
EMAAC	Annual	$165.73	29,287.5	$155.93	29,363.9
	Summer	$165.73	88.0	$155.93	87.9
	Winter	$165.73	1.0	$155.93	1.0
EMAAC Total			29,288.5		29,364.9
PSEG	Annual	$204.29	5,366.6	$204.29	5,366.6
	Summer	$204.29	9.3	$204.29	9.3
	Winter	$204.29	1.0	$204.29	1.0
PSEG Total			5,367.6		5,367.6
BGE	Annual	$200.30	1,937.7	$124.40	2,492.0
	Summer	$200.30	85.0	$124.40	84.6
	Winter	$200.30	0.0	$124.40	0.0
BGE Total			1,937.7		2,492.0
ComEd	Annual	$195.55	22,083.6	$130.04	22,421.0
	Summer	$195.55	274.5	$130.04	274.5
	Winter	$195.55	274.5	$130.04	274.5
ComEd Total			22,358.1		22,695.5
DEOK	Annual	$140.00	2,733.3	$128.47	2,636.3
	Summer	$140.00	25.4	$128.47	25.2
	Winter	$140.00	0.0	$128.47	0.0
DEOK Total			2,733.3		2,636.3

Figure 1 RTO market supply/demand curves: 2021/2022 RPM Base Residual Auction[149 150]



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149 The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW while the prices on the supply curve reflect the smoothing method. The final points on the supply curves generally do not match the price of the highest price offer as a result of the statistical fitting technique, while the MW do match. The smoothed curves are provided consistent with a FERC decision related to the release of RPM data. See, e.g., Motions to Cease and Desist and for Shortened Answer Period of the Independent Market Monitor for PJM (March 25, 2010) and Answer of PJM Interconnection, L.L.C. to Motion to Cease and Desist (March 30, 2010), filed in Docket No. ER09-1063-000, -003.

150 The VRR curve excludes incremental demand which cleared in EMAAC, PSEG, ATSI, ComEd, and BGE.

EMAAC LDA Market Results

Table 48 shows total EMAAC LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity, excluding generation winter capacity, of 33,795.6 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, EMAAC LDA unforced internal capacity increased 622.2 MW from 33,173.4 MW in the 2020/2021 BRA as a result of net generation capacity modifications (79.5 MW), net DR modifications (35.6 MW), and net EE modifications (279.2 MW), the EFORd effect due to lower sell offer EFORds (226.8 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.1 MW). As shown in Table 16, total internal EMAAC unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[151] Total internal EMAAC LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in EMAAC LDA RPM capacity of 33,795.6 MW. RPM capacity was reduced by 670.3 MW of exports, 0.0 MW of FRR optional volumes not offered, 148.6 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 539.5 MW of intermittent resources and 322.8 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (148.6 MW). Subtracting 162.9 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in EMAAC LDA of 31,951.5 MW.[152] After accounting for these exceptions, all capacity resources in EMAAC were offered in the RPM Auction.

The EMAAC LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 29,288.5 MW cleared in EMAAC LDA, 27,426.6 MW were cleared in the RTO before EMAAC LDA became constrained. Once the constraint was binding, based on the 9,000.0 MW CETL value, only the incremental supply located in EMAAC LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,861.9 MW cleared, which resulted in a clearing price for Capacity Performance

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151 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

152 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Resources of $165.73 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and VRR curve.

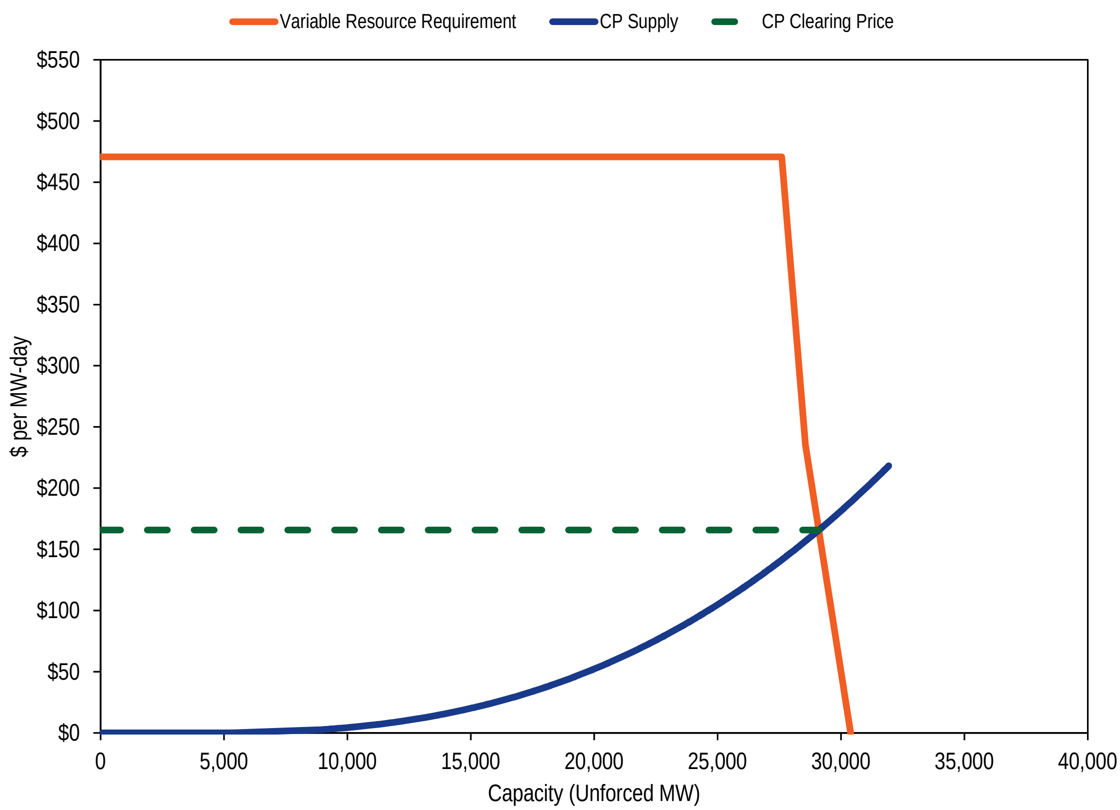
As shown in Table 11, the 28,671.5 MW of cleared and make whole generation and DR for EMAAC LDA and 9,000.0 MW CETL resulted in a net excess of 1,759.2 MW.

Table and Figure for EMAAC LDA

Table 48 EMAAC LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	32,739.9	31,615.9		
DR capacity	1,403.6	1,529.8		
EE capacity	596.0	649.9		
Generation winter capacity	0.0	0.0		
Total internal EMAAC LDA capacity	34,739.5	33,795.6		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	34,739.5	33,795.6		
Exports	(674.0)	(670.3)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(165.2)	(148.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(545.7)	(539.5)		
Unoffered Capacity Storage Resources	(324.4)	(322.8)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(147.0)	(162.9)		
Available	32,883.2	31,951.5	100.0%	100.0%
Generation offered	31,030.6	29,934.7	94.4%	93.7%
DR offered	1,276.1	1,389.6	3.9%	4.3%
EE offered	576.5	627.2	1.8%	2.0%
Total offered	32,883.2	31,951.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 2 EMAAC LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[153]



PSEG LDA Market Results

Table 49 shows total PSEG LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal PSEG LDA unforced capacity, excluding generation winter capacity, of 6,182.7 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, PSEG LDA unforced internal capacity increased 246.4 MW from 5,936.3 MW in the 2020/2021 BRA as a result of net generation capacity modifications (34.7 MW), net DR modifications (35.4 MW), and net EE modifications (141.8 MW), the EFORd effect due to lower sell offer EFORds (34.2 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (0.3 MW). As shown in Table 16, total internal PSEG unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

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[153] The VRR curve is reduced by the CETL and incremental demand which cleared in PSEG.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[154] Total internal PSEG LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in PSEG LDA RPM capacity of 6,182.7 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 148.6 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 46.2 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (148.6 MW). Subtracting 19.3 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in PSEG LDA of 5,968.6 MW.[155] After accounting for these exceptions, all capacity resources in PSEG were offered in the RPM Auction.

The PSEG LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 5,367.6 MW cleared in PSEG LDA, 4,750.1 MW were cleared in the RTO and an additional 352.4 MW were cleared in EMAAC before PSEG LDA became constrained. Once the constraint was binding, based on the 6,902.0 MW CETL value, only the incremental supply located in PSEG LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 265.1 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $204.29 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 11, the 5,127.5 MW of cleared and make whole generation and DR for PSEG LDA and 6,902.0 MW CETL resulted in a net excess of 528.5 MW.

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154 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

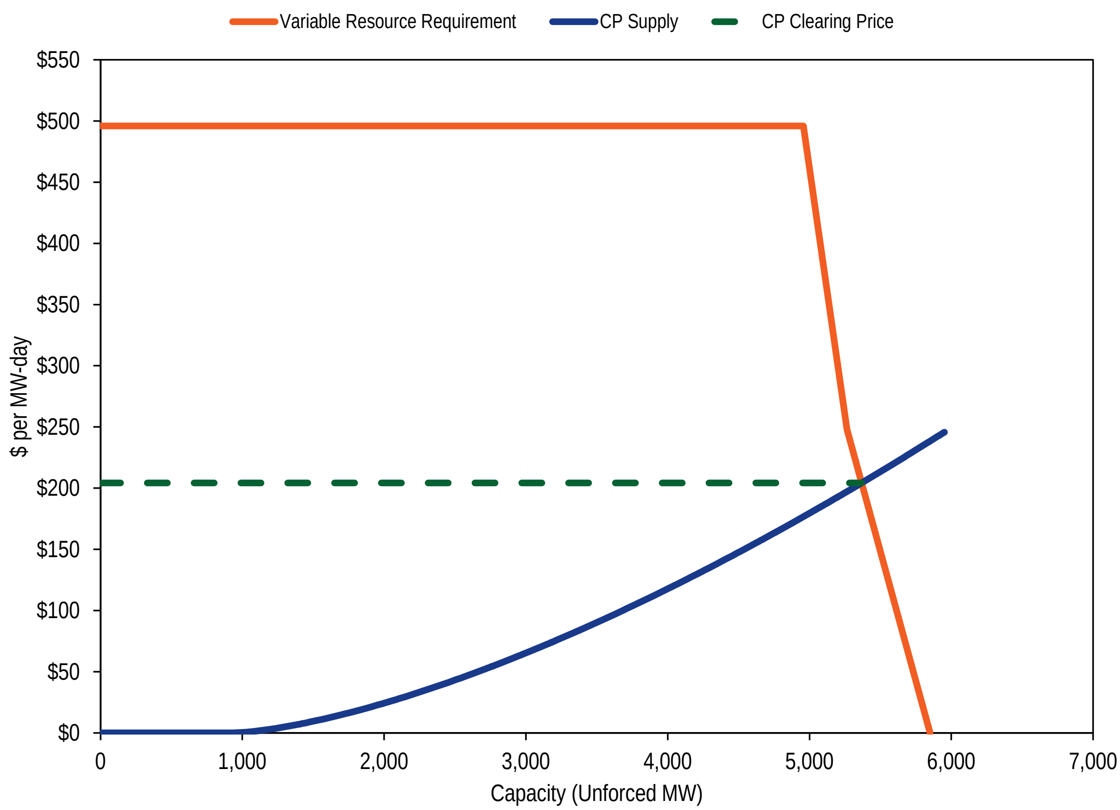
155 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for PSEG LDA

Table 49 PSEG LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	5,838.1	5,497.0		
DR capacity	390.9	426.1		
EE capacity	238.0	259.6		
Generation winter capacity	0.0	0.0		
Total internal PSEG LDA capacity	6,467.0	6,182.7		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	6,467.0	6,182.7		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(165.2)	(148.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(46.2)	(46.2)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(17.2)	(19.3)		
Available	6,238.4	5,968.6	100.0%	100.0%
Generation offered	5,626.7	5,302.2	90.2%	88.8%
DR offered	381.7	415.9	6.1%	7.0%
EE offered	230.0	250.6	3.7%	4.2%
Total offered	6,238.4	5,968.6	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 3 PSEG LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[156]



ATSI LDA Market Results

Table 50 shows total ATSI LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal ATSI LDA unforced capacity, excluding generation winter capacity, of 12,639.2 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, ATSI LDA unforced internal capacity decreased 79.4 MW from 12,718.6 MW in the 2020/2021 BRA as a result of net generation capacity modifications (18.9 MW), net DR modifications (29.4 MW), and net EE modifications (107.0 MW), the EFORd effect due to higher sell offer EFORds (-235.7 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.0 MW). As shown in Table 16, total internal ATSI unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

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156 The VRR curve is reduced by the CETL.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[157] Total internal ATSI LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in ATSI LDA RPM capacity of 12,639.2 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 554.4 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 0.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (551.9 MW) and the resource being reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource (2.5 MW). Subtracting 52.4 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in ATSI LDA of 12,032.4 MW.[158] After accounting for these exceptions, all capacity resources in ATSI were offered in the RPM Auction.

The ATSI LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 8,007.3 MW cleared in ATSI LDA, 6,757.7 MW were cleared in the RTO before ATSI LDA became constrained. Once the constraint was binding, based on the 8,439.0 MW CETL value, only the incremental supply located in ATSI LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,249.6 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $171.33 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 11, the 7,859.1 MW of cleared and make whole generation and DR for ATSI LDA and 8,439.0 MW CETL resulted in a net excess of 700.1 MW.

157 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

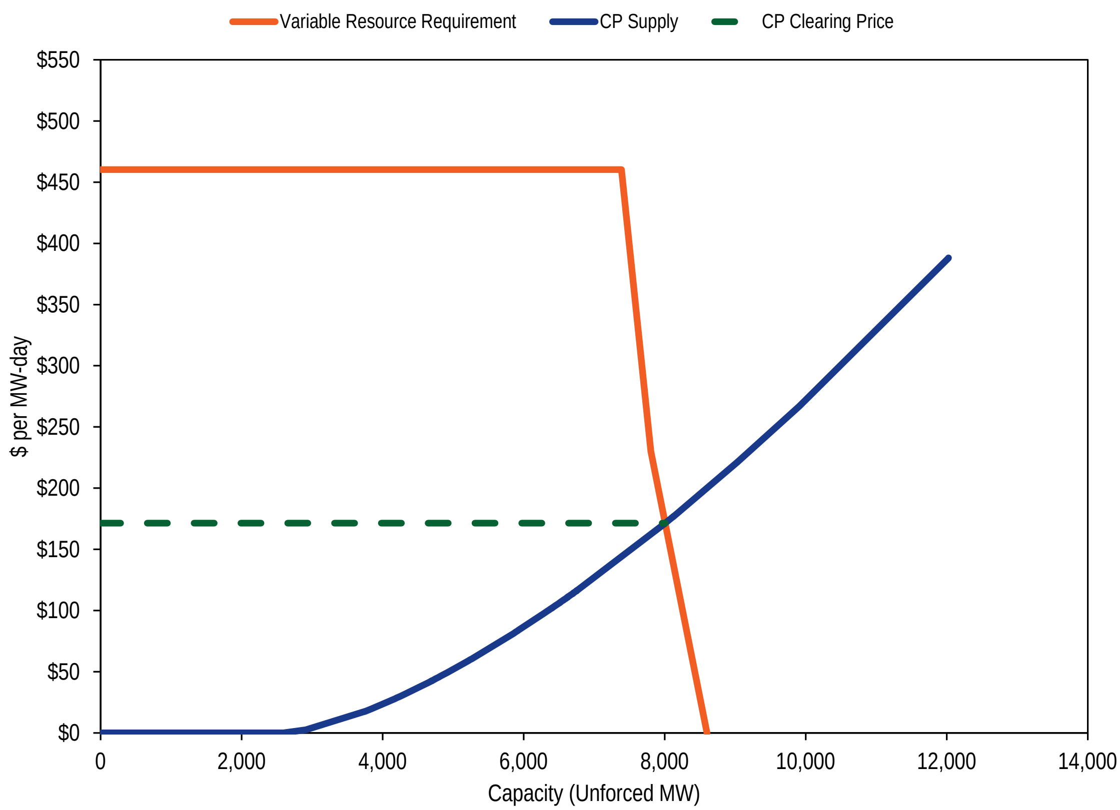
158 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for ATSI LDA

Table 50 ATSI LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	12,743.9	11,218.0		
DR capacity	1,150.2	1,253.4		
EE capacity	153.9	167.8		
Generation winter capacity	0.0	0.0		
Total internal ATSI LDA capacity	14,048.0	12,639.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	14,048.0	12,639.2		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(778.5)	(554.4)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	0.0	0.0		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(47.8)	(52.4)		
Available	13,221.7	12,032.4	100.0%	100.0%
Generation offered	11,965.4	10,663.6	90.5%	88.6%
DR offered	1,120.8	1,221.2	8.5%	10.1%
EE offered	135.5	147.6	1.0%	1.2%
Total offered	13,221.7	12,032.4	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 4 ATSI LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[159]



ComEd LDA Market Results

Table 51 shows total ComEd LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal ComEd LDA unforced capacity, excluding generation winter capacity, of 28,585.9 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, ComEd LDA unforced internal capacity increased 335.1 MW from 28,250.8 MW in the 2020/2021 BRA as a result of net generation capacity modifications (157.8 MW), net DR modifications (87.8 MW), and net EE modifications (-30.7 MW), the EFORd effect due to lower sell offer EFORds (118.4 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (1.8 MW). As shown in Table 16, total internal ComEd unforced winter capacity increased by 112.5 MW for November

[159] The VRR curve is reduced by the CETL.

through April of the 2021/2022 Delivery Year as a result of net generation winter capacity modifications (112.5 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[160] Total internal ComEd LDA capacity was reduced by FRR commitments of 14.7 MW, resulting in ComEd LDA RPM capacity of 28,750.3 MW. RPM capacity was reduced by 541.2 MW of exports, 0.0 MW of FRR optional volumes not offered, 141.5 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 187.0 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. The excused Existing Generation Capacity Resources were the result of the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (141.5 MW). Subtracting 158.6 MW of DR and EE not offered and 74.1 MW of unoffered generation winter capacity resulted in available unforced capacity in ComEd LDA of 27,648.0 MW.[161] After accounting for these exceptions, all capacity resources in ComEd LDA were offered in the RPM Auction.

The ComEd LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 22,358.1 MW cleared in ComEd LDA, 20,624.6 MW were cleared in the RTO before ComEd LDA became constrained. Once the constraint was binding, based on the 5,574.0 MW CETL value, only the incremental supply located in ComEd LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,733.5 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $195.55 per MW-day, as shown in Figure 5. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 11, the 21,587.6 MW of cleared and make whole generation and DR for ComEd LDA and 5,574.0 MW CETL resulted in a net excess of 1,049.6 MW.

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160 "PJM Manual 18: PJM Capacity Market," Rev. 37 (April 27, 2017) at 17.

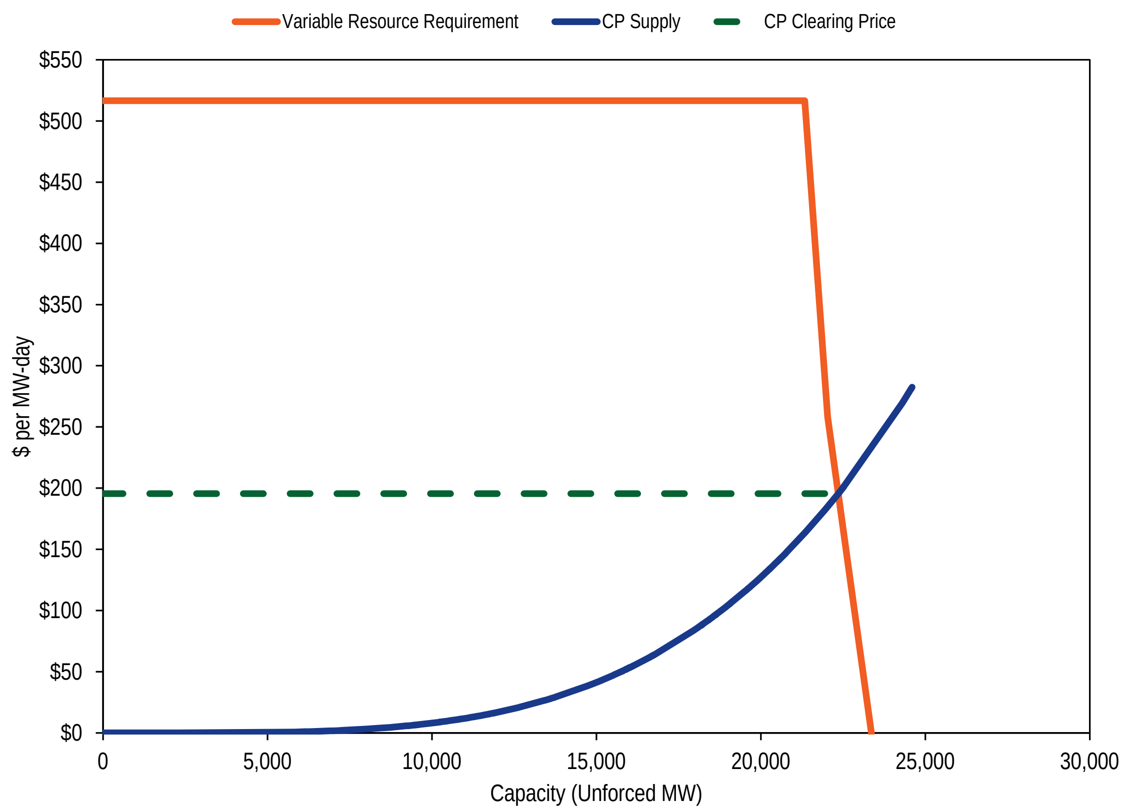
161 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for ComEd LDA

Table 51 ComEd LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	26,225.4	25,705.6		
DR capacity	1,920.1	2,092.7		
EE capacity	722.8	787.6		
Generation winter capacity	179.1	179.1		
Total internal ComEd LDA capacity	29,047.4	28,765.0		
FRR	(14.7)	(14.7)		
Imports	0.0	0.0		
RPM capacity	29,032.7	28,750.3		
Exports	(544.4)	(541.2)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(157.0)	(141.5)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(187.0)	(187.0)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	(74.1)	(74.1)		
Unoffered DR and EE	(145.2)	(158.6)		
Available	27,925.0	27,648.0	100.0%	100.0%
Generation offered	25,427.3	24,926.2	91.1%	90.2%
DR offered	1,828.7	1,992.8	6.5%	7.2%
EE offered	668.9	728.9	2.4%	2.6%
Total offered	27,925.0	27,648.0	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 5 ComEd LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[162]



BGE LDA Market Results

Table 52 shows total BGE LDA offer data for the 2021/2022 RPM Base Residual Auction. Total internal BGE LDA unforced capacity, excluding generation winter capacity, of 3,838.2 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 14, BGE LDA unforced internal capacity decreased 102.3 MW from 3,940.5 MW in the 2020/2021 BRA as a result of net generation capacity modifications (0.0 MW), net DR modifications (-103.6 MW), and net EE modifications (-54.7 MW), the EFORd effect due to lower sell offer EFORds (55.5 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (0.5 MW). As shown in Table 16, total internal BGE unforced winter capacity increased by 0.0 MW for November through April of the 2021/2022 Delivery Year.

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162 The VRR curve is reduced by the CETL.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[163] Total internal BGE LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in BGE LDA RPM capacity of 3,838.2 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 338.6 MW excused from the RPM must offer requirement, 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, and 1.7 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 110.4 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in BGE LDA of 3,387.5 MW.[164] After accounting for these exceptions, all capacity resources in BGE LDA were offered in the RPM Auction.

The BGE LDA import limit was a binding constraint in the 2021/2022 BRA. Of the 1,937.7 MW cleared in BGE LDA, 915.0 MW were cleared in the RTO before BGE LDA became constrained. Once the constraint was binding, based on the 6,005.0 MW CETL value, only the incremental supply located in BGE LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 1,022.7 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $200.30 per MW-day, as shown in Figure 6. The clearing price was determined by the intersection of the incremental supply and VRR curve.

As shown in Table 11, the 1,833.3 MW of cleared and make whole generation and DR for BGE LDA and 6,005.0 MW CETL resulted in a net excess of 189.9 MW.

163 "PJM Manual 18: PJM Capacity Market," Rev. (April 27, 2017) at 17.

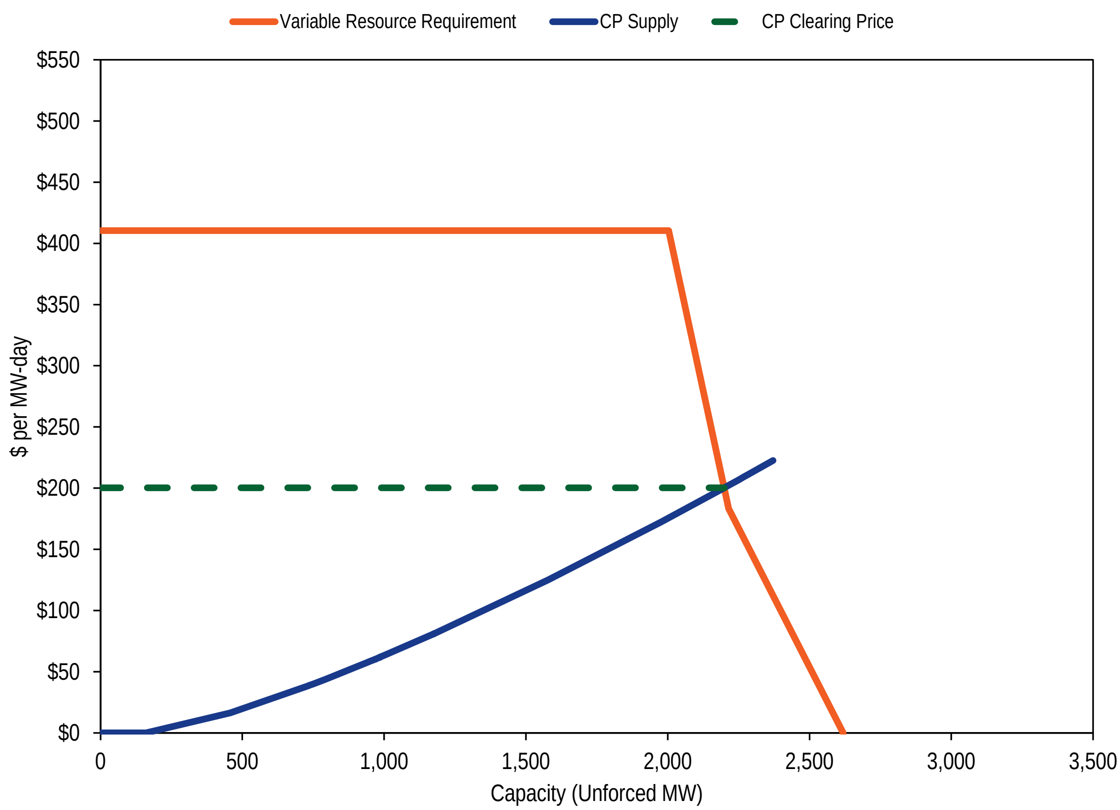
164 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 52 BGE LDA offer statistics: 2021/2022 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	3,527.2	3,329.8		
DR capacity	370.0	403.3		
EE capacity	96.4	105.1		
Generation winter capacity	0.0	0.0		
Total internal BGE LDA capacity	3,993.6	3,838.2		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	3,993.6	3,838.2		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(350.5)	(338.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(4.0)	(1.7)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(100.6)	(110.4)		
Available	3,538.5	3,387.5	100.0%	100.0%
Generation offered	3,172.7	2,989.5	89.7%	88.3%
DR offered	270.1	293.7	7.6%	8.7%
EE offered	95.8	104.3	2.7%	3.1%
Total offered	3,538.5	3,387.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 6 BGE LDA market supply/demand curves: 2021/2022 RPM Base Residual Auction[165]



165 The VRR curve is reduced by the CETL.

Attachment A

Clearing Algorithm for RPM Base Residual Auction

The actual clearing of the RPM Base Residual Auction (BRA) uses a mixed integer optimization algorithm. The purpose of the algorithm is to minimize the cost of procuring unforced capacity given all applicable requirements and constraints, including transmission limits between LDAs, restrictions on coupled sell offers and restrictions specified in credit limited offers.[166] The optimization algorithm calculates clearing prices, which are derived from the shadow prices of the binding resource constraints.

In the BRA, the locational requirement to purchase capacity takes the form of a downward sloping piece-wise linear demand curve called the Variable Resource Requirement (VRR) curve. The VRR curve defines the maximum price for a given level of capacity procurement within each of the constrained LDAs. In the nested LDA structure, the capacity procured towards meeting a child LDA’s Variable Resource Requirement also satisfies the nested parent LDA’s Variable Resource Requirement. A part of the capacity procured for the parent LDA may be transferred to the child LDA up to the defined Capacity Emergency Transfer Limit (CETL) between the parent LDA and the child LDA. For a child LDA, when a CETL constraint binds and limits imports from the parent LDA, higher priced offers that would not clear in an unconstrained market are required to meet demand in the child LDA. The result is a constrained price for the child LDA which is higher than the price for the parent LDA. Accordingly, the shadow price associated with this constraint, called the locational price adder, should accurately account for the additional cost of meeting the internal requirement for capacity. Implementing this constraint for a nested LDA structure, while preserving the linearity of the optimization problem, poses a particular computational challenge.

The RPM algorithm co-optimizes the cost of procuring a child LDA’s and the parent LDA’s capacity to meet their respective Variable Resource Requirements. Since the capacity procured for the child LDA jointly satisfies its own and its parent LDA’s VRR, the parent LDA’s VRR curve needs to be reconfigured to take into account the child LDA’s cleared capacity. Any such reconfiguration may result in a different solution for the child LDA. In the RPM algorithm, the mixed integer optimization problem is solved iteratively, where after every iteration, the parent LDAs’ VRR curves are reconfigured to reflect their respective child LDAs’ cleared capacity. The process is repeated until an

[166] OATT Attachment DD § 5.12(a).

equilibrium point is reached. The method preserves the mixed integer feature of the optimization problem while allowing for incorporation of the resource constraints. Under this approach, the price adders are directly obtained as shadow prices of the import limit constraints. Prior to the 2017/2018 BRA, the price adders for annual and extended summer resources were obtained from the shadow prices associated with the respective binding constraints. Effective with the 2017/2018 BRA, PJM replaced the minimum requirements for Annual and Extended Summer DR products with limits on the maximum amount of Limited and Extended Summer DR products. As a result, effective with the 2017/2018 BRA, the price adder for Annual Resources is obtained as the shadow price of the import limit constraint for any constrained child LDA. The price decrements for Limited and Extended Summer DR products are obtained from the shadow prices associated with the respective binding maximum resource constraints. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource and Energy Efficiency (DR/EE) Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint, are established for each modeled LDA. As a result, effective for the 2018/2019 and the 2019/2020 Delivery Years, the price adder for Capacity Performance Resources is obtained as the shadow price of the import limit constraint for any constrained child LDA. The price decrements for Base Capacity Resources and Base Capacity DR/EE Resources are obtained from the shadow prices associated with the respective binding maximum resource constraints. Effective for 2020/2021 and subsequent Delivery Years, the Base Capacity Resource Constraint and the Base Capacity Demand Resource and Energy Efficiency (DR/EE) Constraint were eliminated since only Capacity Performance resources were allowed to offer in the BRA.

In the BRA, Capacity Market Sellers are allowed to specify a minimum level of unforced capacity for any resource offered into the auction. If any such inflexible offers are marginal or close to marginal, the PJM's RPM algorithm relaxes the minimum bound on those offers and re-solves the optimization, thus allowing those offers to clear below the specified lower bound. In the BRA, any resource that cleared at a MW level below the specified minimum level receives a make whole payment for the difference between the minimum bound and the unconstrained cleared MW, at the clearing price. However, the PJM approach does not consider the additional cost of make whole payments as part of the overall optimization objective. The alternative to clearing an inflexible offer will generally be the clearing of a higher priced offer to satisfy the applicable resource requirements without a make whole payment. In the MMU's approach, the RPM algorithm explicitly compares solutions with make whole against solutions without make whole payments to arrive at the optimal solution.

Possible Reasons for Differences between PJM and MMU Solutions

It is possible for the MMU's solution to the BRA optimization problem to differ from PJM's solution although these differences are usually small. The following are some of the reasons which may contribute to differences between the MMU's solution and PJM's solution:

1. Optimization Tolerance: All mixed integer programming solvers use numerical methods to determine the optimal solution. These methods are of finite arithmetic precision. Therefore, the search path and eventually the final solution depend on the chosen tolerance levels. In general, tighter tolerance levels are associated with longer computational times. One of the tolerance criteria used by mixed integer programming solvers is specified as a limit on the execution time. When execution time is a tolerance criterion, it is possible for solutions to diverge slightly, even with identical resource limit criteria, due to differences in the speed of the computers on which the solver is run.
2. Algorithm: The solution approach involves iteratively solving a mixed integer problem to locate the optimal solution given all the applicable business rules. The tolerance of the criteria used to evaluate feasible solutions in the iterative approach is also likely to affect the final solution. For example, using a slightly different criterion for the equilibrium point in the reconfiguration of the parent LDA's VRR curve could result in negligible impact on cleared quantities, but the impact on shadow prices and consequently marginal clearing prices could be substantial. The iterative approach where a sequence of the mixed integer problems are solved, contributes to the instability of the final solution.
3. Non-unique solution: It is possible for the BRA optimization problem to have non-unique solutions. Identical inputs could result in slightly different solutions with exactly the same objective value within the chosen tolerance levels each time the solution is calculated.

Comparison of PJM and MMU Solutions

The results of the 2021/2022 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every constrained nested LDA using the MMU's algorithm is identical to the corresponding total MW cleared under PJM's method. The total MW cleared for the entire RTO using the MMU's algorithm is identical to the total MW cleared under PJM's method. The clearing prices using the PJM's approach were identical to the clearing prices under MMU's method.

Recommendations for the RPM Market Clearing

The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. For example, under the current structure, any capacity transfer between the Dominion LDA, which is modeled within the Rest of the RTO LDA, and the Pepco LDA needs to pass through MAAC and SWMAAC LDAs, although Dominion and Pepco regions are linked by several transmission lines.

Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use non-nested model with all LDAs and specify VRR curves for each LDA. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints.

The nested structure also contributes to an important inefficiency in the clearing of resources. Under the existing nested structure, every resource is eligible to satisfy the reliability requirement of the LDA where the resource is located and also all the higher level parent LDAs to which it belongs. For instance, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, PSEG, EMAAC, MAAC and RTO. However, the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the requirement of a higher level LDA yields a larger consumer surplus than clearing that resource in a lower level LDA. For example, a capacity resource located in the child LDA PSEG North always results in a higher or equal consumer surplus if it clears to meet the parent LDA PSEG's requirement, instead of clearing to satisfy PSEG North's requirement. The optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. As a result, the optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. As a result of this feature of the optimization model, a constraint is added to the model to force meeting the requirements of child LDAs before the requirements of parent LDAs. Without such constraints, the clearing process using a nested LDA model would produce implausible outcomes.

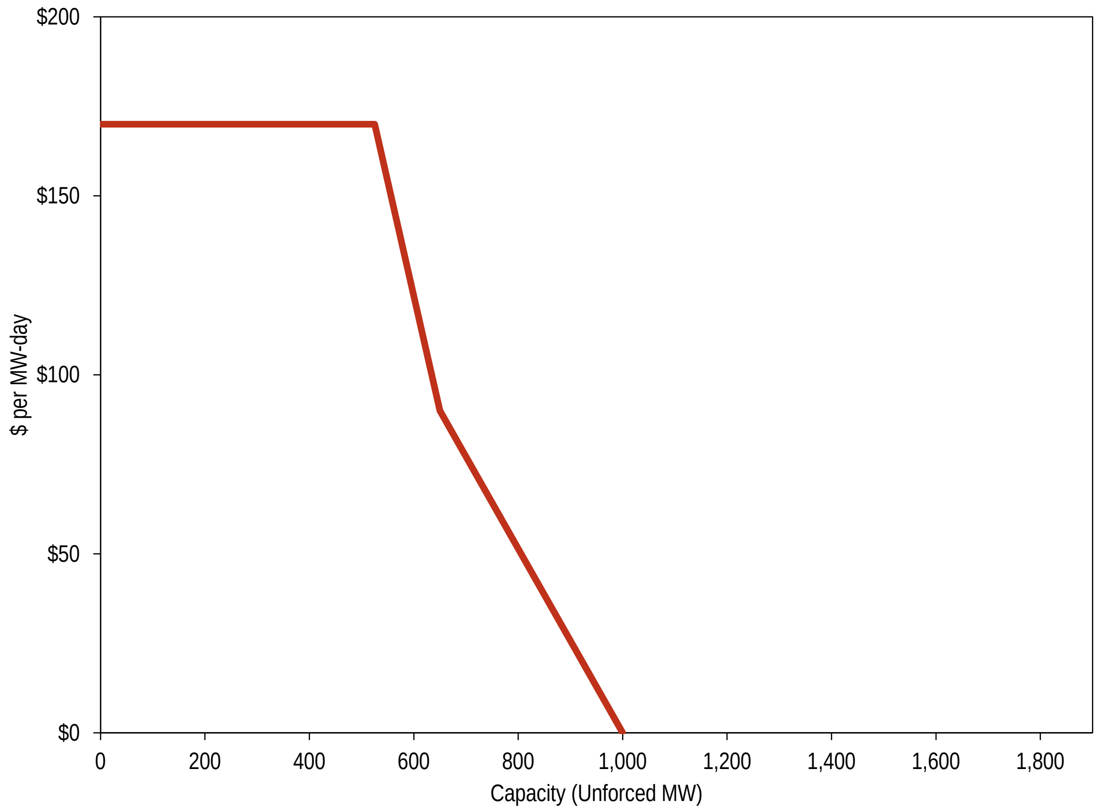
The MMU recommends improving the RPM solution method related to make whole payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.

Illustration of BRA Clearing Algorithm

The objective function in the auction optimization algorithm is to maximize the area between the RTO VRR curve and the supply curve from the origin to the clearing price while simultaneously satisfying the LDA import limits and minimum resource requirements. The objective ensures that the total cost of procurement is minimized while the highest offer cleared, bounded by the VRR curve, sets the clearing price. The auction clearing process is equivalent to choosing the price and quantity that maximize total welfare, where the VRR curve is the demand curve and capacity offers are the supply curve.

Figure 7 and Figure 8 show an example child VRR and parent VRR curves. To illustrate the price formation in the BRA, two example scenarios are presented. In the first scenario, a higher CETL is assumed between the parent LDA and the child LDA. In the second scenario, a lower CETL is assumed between the parent LDA and the child LDA. All other offers and parameters are identical in the two scenarios. In both scenarios, only one type of resource and only one requirement are considered.[167]

Figure 7 Variable resource requirement curve: child LDA



[167] For simplicity, the Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint are not included.

Figure 8 Nested variable resource requirement curve: parent LDA

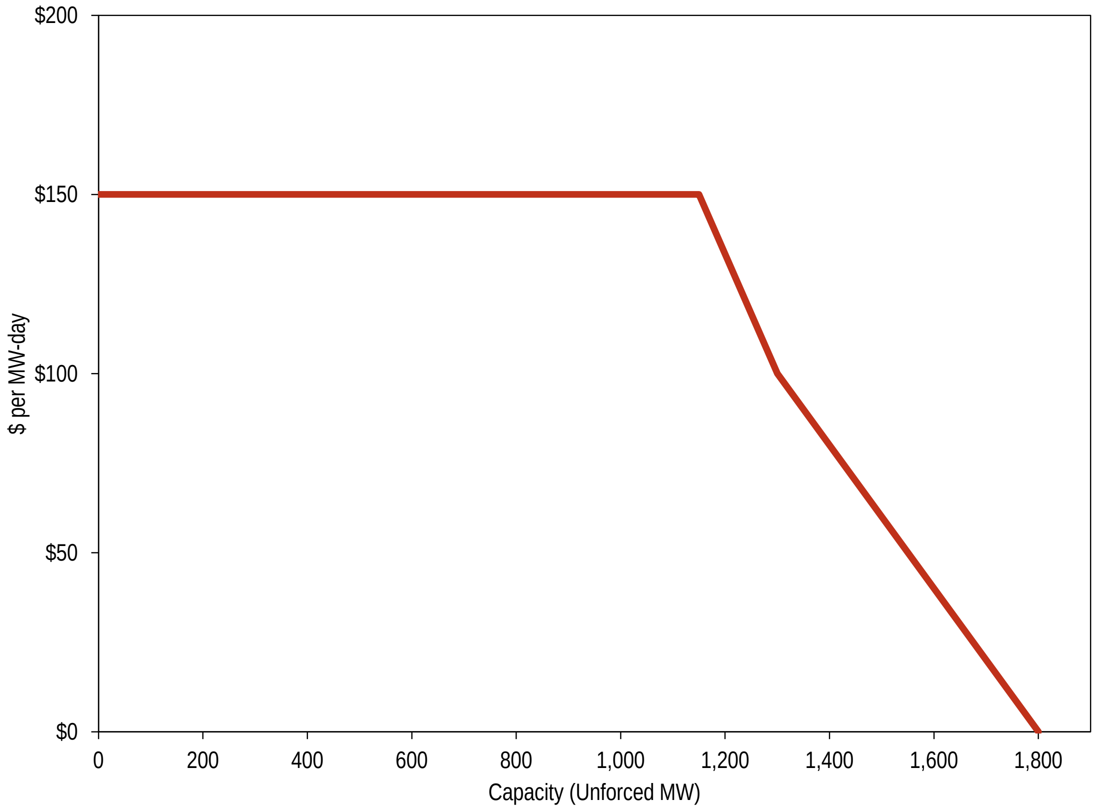


Figure 9 and Figure 10 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is $120.00.

Figure 9 Optimal solution for scenario 1: child LDA

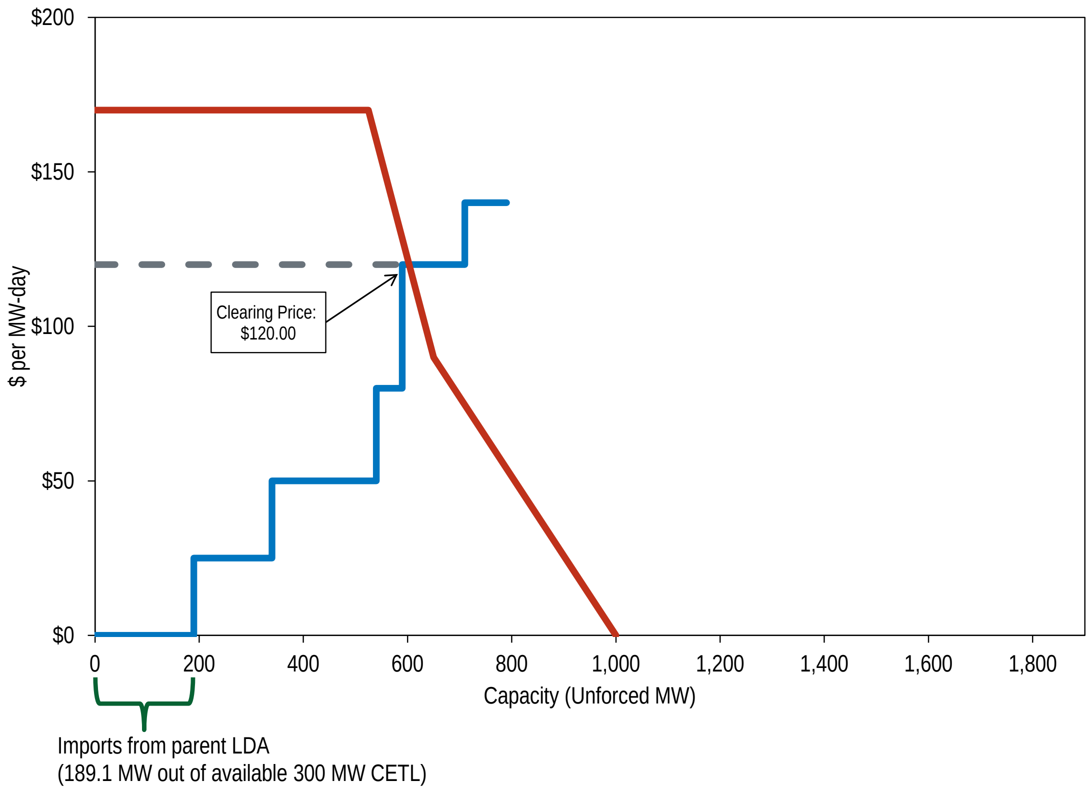


Figure 10 Optimal solution for scenario 1: Parent LDA

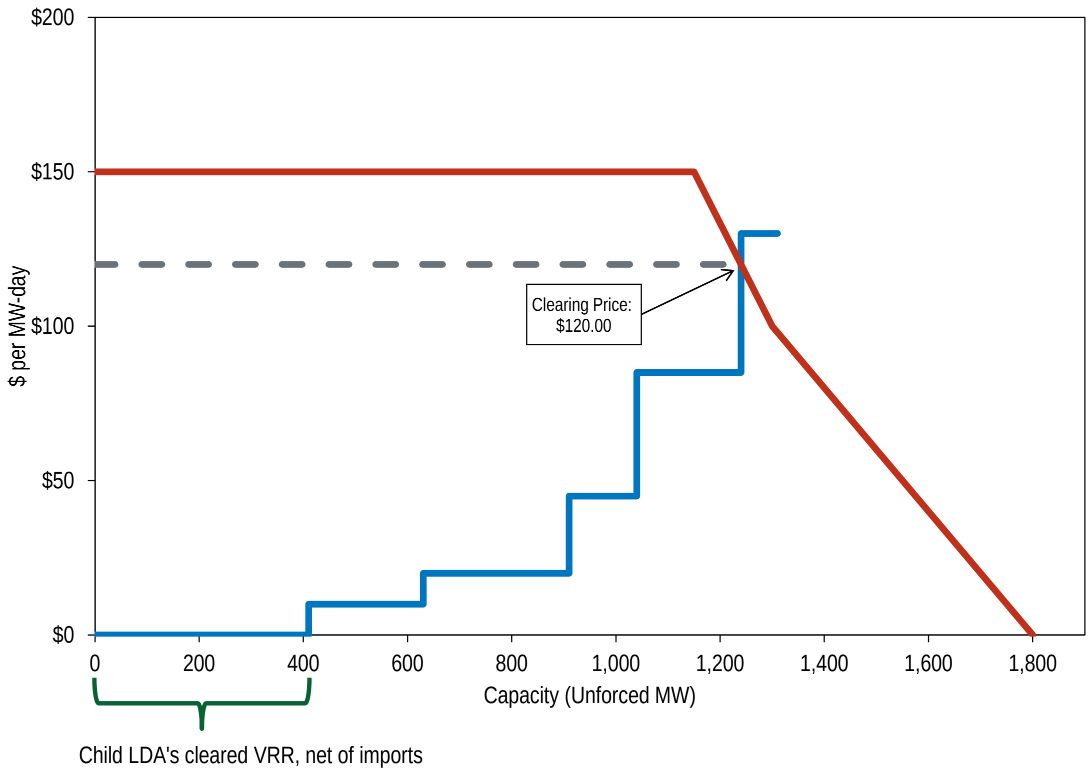


Figure 11 and Figure 12 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA to import capacity from the parent LDA. Out of merit, higher price offers, relative to the ones cleared for the parent LDA, are needed to meet the Variable Resource Requirement of the child LDA. The shadow price of the binding CETL constraint, $13.30 per MW-day, reflects the tradeoff between a clearing a resource from child LDA against clearing a resource from the parent LDA. The marginal clearing prices of the parent LDA and the child LDA are $106.70 and $120.00 per MW-day.

Figure 11 Optimal solution for scenario 2: Child LDA

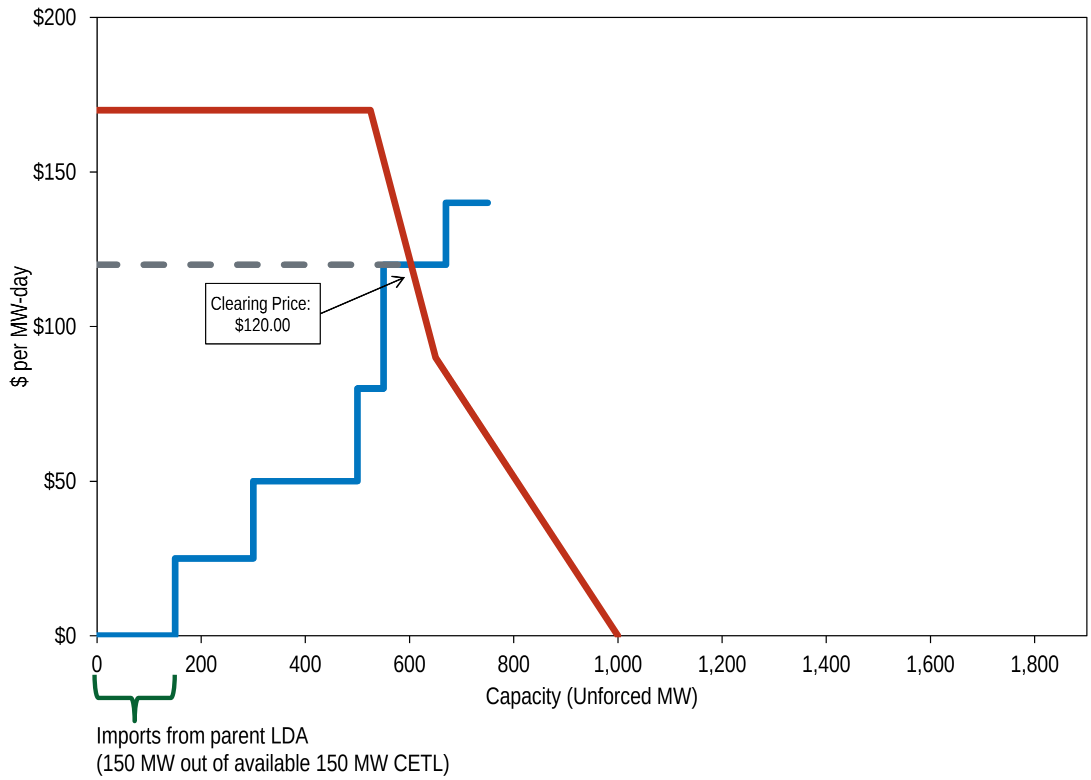
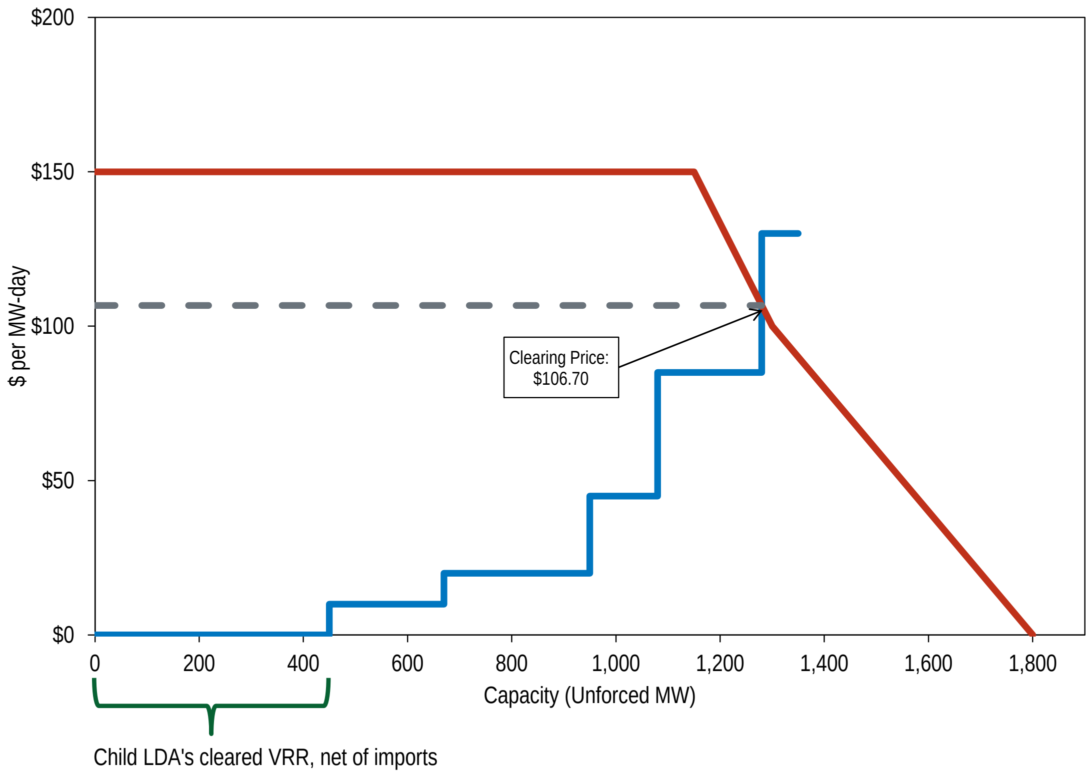


Figure 12 Optimal solution for scenario 2: Parent LDA



Attachment B

Competitive offer for a Capacity Performance resource in PJM

This attachment describes the mathematics of the calculation of a competitive capacity performance resource offer in PJM.

Definitions

R^c – net revenue for a resource with a capacity commitment

R^{nc} – net revenue for a resource without a capacity commitment that sells energy and ancillary services

$A_i = (MW_i/UCAP)$, availability during performance assessment interval i, calculated as the MW power output in an interval divided by the MW UCAP of the resource. The MWh output in an interval is equal to one-twelfth of the MW power output of the resource.

$\bar{A}$ - average availability across all performance assessment intervals defined as $\sum_{\mathrm{i}=1}^{\mathrm{H}} \mathrm{MW_i}/(\mathrm{H} \times \mathrm{UCAP})$

B_i – balancing ratio during performance assessment interval i, ratio of total load and reserve requirement during the hour to total committed UCAP.

$\bar{B}$ – average balancing ratio across all performance assessment intervals in a delivery year

H – expected value of total number of performance assessment intervals in a delivery year

$CPBR_i$ – capacity performance bonus rate for interval i in ($ per MWh), varies by interval

CPBR – average capacity performance bonus rate over all performance assessment intervals ($ per MWh) in a delivery year, calculated as $\sum_{i=1}^{H}(CPBR_i \times A_i)/(H \times \bar{A})$

PPR – nonperformance charge rate ($ per MWh; net CONE in $ per ICAP MW-year divided by 30, fixed for the delivery year for a particular net CONE area)

ACR – net ACR (net going forward costs) for the resource on a per MW UCAP basis, not including any risk premium.

p – offer price in RPM on a $ per MW-year UCAP basis

Competitive Offer for an underperforming resource

If a resource is expected to underperform i.e., when expected $A_i < B_i$ for all PAI:

The net revenue for a resource that has a capacity commitment, R^c, is calculated as:

$$R^c = UCAP \times [p + \ (PPR \times H \times (\bar{A} - \bar{B}))/12] - UCAP \times ACR \quad (1)$$

This can be summarized as the MW of capacity multiplied by the capacity clearing price net of performance penalties less the annual avoidable costs of operating the unit.

The net revenue for that same resource that does not have a capacity commitment but participates in the energy and ancillary services markets and earns capacity bonus performance payments, R^{nc}, is calculated as:

$$R^{nc} = UCAP \times \left[\ (1/12) \sum_{i=1}^{H} (CPBR_i \times A_i)\right] - UCAP \times ACR \quad (2)$$

This can be summarized as the MW of capacity multiplied by the bonus payments less the annual avoidable costs of operating the unit.

In equation (2) since the resource does not have a capacity performance obligation, the resource earns capacity bonus performance payments for all of its energy and reserves during performance assessment intervals.

Low ACR case

If $R^{nc} \geq 0$, a resource is expected to make enough revenues to cover net going forward costs without a capacity commitment and has the opportunity to be profitable as an energy only resource in the CP design.

$$if\ ACR \leq \left(\frac{1}{12}\right) \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq (CPBR \times H \times \bar{A})/12$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue with the capacity performance obligation must be greater than or equal to the expected revenue as an energy only resource, or $R^c \geq R^{nc}$.

Taking on a capacity obligation is profitable and competitive if: $R^c - R^{nc} \ \geq \ 0$. R^c and R^{nc} are defined in equation (1) and equation (2).

Thus, the competitive offer and therefore the expected equilibrium clearing price in RPM equals a value of p such that equation (1) minus equation (2) is greater than or equal to zero:

$$p \geq \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - \left(\frac{1}{12}\right)(PPR \times H \times (\bar{A} - \bar{B}))$$

$$or, p \geq \frac{PPR \times H \times \bar{B}}{12} + \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i)\right] - \frac{PPR \times H \times \bar{A}}{12}$$

Using the weighted average capacity performance bonus rate,

$$p \geq \left(\frac{1}{12}\right)[PPR \times H \times \bar{B} + CPBR \times H \times \bar{A} - PPR \times H \times \bar{A}]$$

Therefore the competitive offer is:

$$p = \left(\frac{1}{12}\right)\ [CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A})] \tag{3}$$

Equation (3) is the competitive offer formula for a low ACR resource with $A_i < B_i$ for all PAI. The competitive offer for a low ACR resource equals the expected bonus payments less the expected nonperformance charges.

Using PJM's formula for PPR as net CONE divided by 30, the competitive offer is:

$$p = \left(\frac{1}{12}\right)\left[CPBR \times H \times \bar{A} + \left(\frac{Net\ CONE}{30}\right) \times H \times (\bar{B} - \bar{A})\right] \tag{4}$$

If (i) the capacity performance bonus rate is assumed to be equal to the capacity nonperformance charge rate and, (ii) the number of expected performance assessment intervals, H, is expected to be 360 (30 hours), this is identical to:

$$p = \ Net\ CONE \times \bar{B} \tag{5}$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing. However, if the expected number of performance assessment intervals(H) is updated to a smaller number, say 60 intervals (5 hours), and if the assumption of a low ACR resource still holds true ($ACR \leq (CPBR \times H \times \bar{A})/12$), the competitive offer for such a resource is:

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

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

Under this updated estimate for the number of performance assessment intervals, more resources are likely to have their net ACR greater than the energy only bonuses, and become 'High ACR' resources. The competitive offers for High ACR resources are discussed in the following section.

The actual capacity performance bonus rate (CPBR) will depend on the level of nonperformance charges collected from underperforming resources during each performance assessment interval. The maximum value of CPBR is the nonperformance charge rate, PPR, which occurs when no resource is exempted for under performance for any reason. If resources are exempted for under performance, the CPBR would decrease and the competitive offer would decrease because the value of being an energy only resource and relying solely on bonus payments would decrease as the value of the bonus payments decreases.

High ACR case

If $R^{nc} < 0$, a resource is not expected to make enough revenues to cover net going forward costs without a capacity payment.

$$if\ ACR > \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right]$$

$$or\ ACR > (CPBR \times H \times \bar{A})/12$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue from the capacity payment and any bonus payments must be enough to cover all the costs of the unit including ACR and any capacity nonperformance charges. (The definition of an underperforming resource means that $A_i < B_i$ for all PAI and that the resource is expected to incur net nonperformance charges if it has a capacity performance obligation.)

If taking on a capacity obligation is to be profitable and competitive: $R^c \geq 0$.

From equation (1):

$$UCAP \times [p + (PPR \times H \times (\bar{A} - \bar{B}))/12] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12$$

The competitive offer is:

$$p = ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12 \qquad (6)$$

The competitive offer for a High ACR unit equals avoidable costs plus expected nonperformance charges.

Comparing equation (3) (Low ACR unit competitive offer) and equation (6) (High ACR unit competitive offer), there is a common component of $(PPR \times H \times (\bar{B} - \bar{A}))/12$ in both equations. For a unit to be High ACR, $ACR > (CPBR \times H \times \bar{A})/12$. Comparing equations (3) and (6) and the assumption for a High ACR unit, the High ACR unit competitive offer from equation (6) is always greater than the Low ACR unit competitive offer from equation (3).

Competitive Offer for an overperforming resource

If a resource is expected to overperform i.e., when expected $A_i > B_i$ for all PAI:

The total net revenue for a resource that has a capacity commitment, R^c, is calculated as:

$$R^c = UCAP \times p + UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \quad (7)$$

This can be summarized as the MW of capacity multiplied by the capacity clearing price plus performance bonuses less the annual avoidable costs of operating the unit.

The total net revenue for that same resource that does not have a capacity commitment but participates in the energy and ancillary services markets and earns capacity bonus performance payments, R^{nc}, is calculated as:

$$R^{nc} = UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right] - UCAP \times ACR \quad (8)$$

This can be summarized as the MW of capacity multiplied by the bonus payments less the annual avoidable costs of operating the unit.

In equation (8) since the resource does not have a capacity performance obligation, the resource earns capacity bonus performance payments for all of its energy and reserves during performance assessment intervals.

Low ACR case

If $R^{nc} \geq 0$, a resource is expected to make enough revenues to cover net going forward costs without a capacity commitment and has the opportunity to be profitable as an energy only resource in the CP design.

$$if\ ACR \leq \left(\frac{1}{12}\right)\sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq (CPBR \times H \times \bar{A})/12$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue with the capacity performance obligation must be greater than or equal to the expected revenue as an energy only resource, or $R^c \geq R^{nc}$.

Taking on a capacity obligation is profitable and competitive if: $R^c - R^{nc} \geq 0$. R^c and R^{nc} are defined in equation (7) and equation (8).

Thus, the competitive offer and therefore the expected equilibrium clearing price in RPM equals a value of p such that equation (7) minus equation (8) is greater than or equal to zero:

$$p \geq \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (B_i)\right]$$

$$or, p \geq (CPBR \times H \times \bar{B})/12 \tag{9}$$

Equation (9) is the competitive offer formula for a low ACR resource with $A_i > B_i$ for all PAI.

If (i) the capacity performance bonus rate is assumed to be equal to the capacity nonperformance charge rate (net CONE divided by 30) and, (ii) the number of expected performance intervals, H, is expected to be 360, this is identical to:

$$p = net\ CONE \times \bar{B} \tag{10}$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing. However, if the expected number of performance assessment intervals(H) is updated to a smaller number, say 60 intervals (5 hours), and if the assumption of a low ACR resource still holds true ($ACR \leq (CPBR \times H \times \bar{A})/12$), the competitive offer for such a resource is:

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

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

Under this updated estimate for the number of performance assessment intervals, more resources are likely to have their net ACR greater than the energy only bonuses, and become 'High ACR' resources. The competitive offers for High ACR resources are discussed in the following section.

High ACR case

If $R^{nc} < 0$, a resource is not expected to make enough revenues to cover net going forward costs without a capacity payment.

$$if\ ACR > \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H}(CPBR_i \times A_i)\right]$$

$$or\ ACR > (CPBR \times H \times \bar{A})/12$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the CP design, the expected revenue from the capacity payment and any bonus payments must be enough to cover all the costs of the unit including ACR. (The definition of an overperforming resource means that $A_i > B_i$ for all PAI and that the resource is expected to receive capacity performance bonus revenues.)

If taking on a capacity obligation is to be profitable and competitive: $R^c \geq 0$.

From equation (7):

$$UCAP \times p + UCAP \times \left(\frac{1}{12}\right)\left[\sum_{i=1}^{H} CPBR_i \times (A_i - B_i)\right] - UCAP \times ACR \geq 0$$

$$or, p \geq ACR + \left(\frac{1}{12}\right) \times CPBR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

$$p = ACR + (CPBR \times H \times (\bar{B} - \bar{A}))/12 \qquad (11)$$

The competitive offer for a High ACR unit equals avoidable costs net of expected bonus performance revenues.

The assumption that makes a unit High ACR is, $ACR > (CPBR \times H \times \bar{A})/12$. Comparing equations (9) and (11) and the assumption for a High ACR unit, the High ACR unit competitive offer from equation (11) is always greater than the Low ACR unit competitive offer from equation (9).

If the capacity performance bonus rate is equal to the capacity nonperformance charge rate, the competitive offer for a Low ACR unit is equal to $(PPR \times H \times \bar{B})/12$ regardless of the performance of the unit and the competitive offer for a High ACR unit is equal to $ACR + (PPR \times H \times (\bar{B} - \bar{A}))/12$ regardless of the performance of the unit.

Revision History

August 9, 2018: Original document posted.

August 24, 2018: Scenario 21 Impact of noncompetitive offers was revised.

October 4, 2019: Capacity Transmission Rights values were revised.

Attachment D

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

The MMU is also tracking PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2020 Quarterly State of the Market Report for PJM: January through June*, the MMU includes three new recommendations.

New Recommendation from Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all units going into service since the change in the tax code. The CRF rates should be updated at least annually to reflect current interest rates and changes in federal or state taxes, including depreciation treatment and tax rates. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources and the current tax rate and interest rate. (Priority: High. New recommendation. Status: Not adopted.)

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends a requirement that the details of all bilateral transactions be reported to PJM. (Priority: High. New recommendation. Status: Not adopted.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Adopted 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000

per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that market sellers not be allowed to designate any portion of an available capacity resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[7] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Adopted 2020.)

7 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[8] [9] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)

8 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

9 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Partially adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead operating reserves to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
    - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

- — The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- — The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[10])
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the day-ahead and the real-time energy markets and the associated operating reserve charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[11])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch.

10 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

11 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Section 5, Capacity Market

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[12] [13] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[14] [15] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity

12 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
13 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
14 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
15 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[16] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and

16 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

17 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 6, Demand Response

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component

of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[18] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[19] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)

18 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

19 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[20])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)

20 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported Q1 2020. Status: Not adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: High. First reported 2013. Status: Partially adopted, Q2 2020.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing

authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 10, Ancillary Services

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[21])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[22] FERC rejected.[23])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[24])

21 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
22 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
23 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
24 *Id.*

- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[25])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[26])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Partially Adopted 2019.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)

25 *Id.*
26 *Id.*

- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR market be based on opportunity cost only in order to mitigate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all units going into service since the change in the tax code. The CRF rates should be updated at least annually to reflect current interest rates and changes in federal or state taxes, including depreciation treatment and tax rates. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources and the current tax rate and interest rate. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[27] Status: Partially adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[28] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Status: Adopted, 2019.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to

27 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

28 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Adopted.)

Cost Allocation

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[29] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

29 See the *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[30] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Adopted, 2019. Pending at FERC.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral transactions be reported to PJM. (Priority: High. New recommendation. Status: Not adopted.)

30 See "PJM Manual 6: Financial Transmission Rights," Rev. 24 (April 15, 2020).

Attachment E

Energy Market

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first six months of 2020.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first six months of 2020 was unconcentrated by FERC HHI standards. Average HHI was 748 with a minimum of 543 and a maximum of 1083 in the first six months of 2020. The peaking segment of supply was highly concentrated. The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[2] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. Units with market power have positive markups, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

1 OATT Attachment M (PJM Market Monitoring Plan).

2 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

Overview

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 123,217 MW for the 2020 spring, and 127,128 MW for the 2019 spring. In the first six months of 2020, 436 MW of new resources were added in the energy market, 1,932 MW of internal resources and 457 MW of pseudo tied resources retired.

  PJM average hourly real-time cleared generation in the first six months of 2020 decreased by 5.0 percent from the first six months of 2019, from 91,613 MWh to 87,044 MWh.

  PJM average hourly day-ahead cleared supply in the first six months of 2020, including INCs and up to congestion transactions, decreased by 5.5 percent from the first six months of 2019, from 115,511 MWh to 109,126 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first six months of 2020 was 127,919 MWh in the HE 1600 on June 10, 2020, which was 6,141 MWh, 4.6 percent, lower than the PJM peak load in the first six months of 2019, which was 134,060 MWh in the HE 0800 on January 31, 2019.

  PJM average hourly real-time demand in the first six months of 2020 decreased by 5.8 percent from the first six months of 2019, from 86,297 MWh to 81,255 MWh. PJM average hourly day-ahead demand in the first six months of 2020, including DECs and up to congestion transactions, decreased by 6.1 percent from the first six months of 2019, from 110,890 MWh to 104,164 MWh.

Market Behavior

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. In the first six months of 2020, 16.8 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchases and 60.0 percent by self-supply. Compared to the first six months of 2019, reliance on bilateral contracts increased by 1.2 percentage points, reliance on spot market purchases decreased by 1.7 percentage points and reliance on self-supply increased by 0.5 percentage points.
- **Generator Offers.** Generator offers are categorized as pool scheduled and self scheduled. Units which are available for economic commitment are pool scheduled. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offered MW, up to economic maximum output, in the first six months of 2020, 64.7 percent were offered to be pool scheduled, 33.0 percent above economic minimum and 31.7 percent at the economic minimum. For self scheduled units, 14.2 percent were offered as self scheduled at a fixed output, and 21.1 percent were offered as self scheduled and dispatchable.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 14.0 percent and cleared MW decreased by 13.4 percent in the first six months of 2020. The hourly average submitted decrement offer MW increased by 15.6 percent and cleared MW decreased by 2.8 percent in the first six months of 2020. The hourly average submitted up to congestion bid MW decreased by 32.8 percent and cleared MW decreased by 5.8 percent in the first six months of 2020.

Market Performance

- **Generation Fuel Mix.** In the first six months of 2020, coal units provided 17.7 percent, nuclear units 35.5 percent and natural gas units 39.3 percent of total generation. Compared to the first six months of 2019, generation from coal units decreased 32.1 percent, generation from natural gas units increased 11.7 percent and generation from nuclear units decreased 1.6 percent. The trend toward more energy from natural gas and less from coal accelerated in the first six months of 2020.
- **Fuel Diversity.** The fuel diversity of energy generation in the first six months of 2020, measured by the fuel diversity index for energy (FDI_e), decreased 2.5 percent compared to the first six months of 2019.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2020, coal units were 16.4 percent and natural gas units were 74.0 percent of marginal resources. In the first six months of 2019, coal units were 26.6 percent and natural gas units were 68.1 percent of marginal resources.

  In the PJM Day-Ahead Energy Market, in the first six months of 2020, up to congestion transactions were 52.3 percent, INCs were 14.3 percent, DECs were 14.2 percent, and generation resources were 19.2 percent of marginal resources. In the first six months of 2019, up to congestion transactions were 57.8 percent, INCs were 13.3 percent, DECs were 18.2 percent, and generation resources were 10.5 percent of marginal resources.

- **Prices.** PJM real-time and day-ahead energy market prices were at the lowest level in the history of PJM markets during the first six months of 2020. Both the weather and COVID-19 played a role in this significant drop in prices.

  PJM real-time energy market prices decreased in the first six months of 2020. The load-weighted, average real-time LMP was 29.4 percent lower in the first six months of 2020 than in the first six months of 2019, $19.40 per MWh versus $27.49 per MWh.

  PJM day-ahead energy market prices decreased in the first six months of 2020. The load-weighted, average day-ahead LMP was 31.3 percent lower in the first six months of 2020 than in the first six months of 2019, $19.23 per MWh versus $27.97 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first six months of 2020, 29.1 percent of the load-weighted LMP was the result of coal costs, 43.3 percent was the result of gas costs and 1.86 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first six months of 2020, 31.2 percent of the load-weighted LMP was the result of coal costs, 19.4 percent was the result of gas costs, 14.0 percent was the result of INC offers, 18.4 percent was the result of DEC bids, and 3.2 percent was the result of up to congestion transaction offers.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was $0.15 per MWh in the first six months of 2020, and -$0.45 per MWh in the first six months of 2019. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were two intervals with five minute shortage pricing in the first six months of 2020. There were no emergency actions that resulted in Performance Assessment Intervals in the first six months of 2020.
- There were 874 five minute intervals, or 1.7 percent of all five minute intervals in the first six months of 2020 for which at least one solved RT SCED case showed a shortage of reserves, and 364 five minute intervals, or 0.7 percent of all five minute intervals in the first six months of 2020 for which more than one solved RT SCED case showed a shortage of reserves. PJM triggered shortage pricing for two five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.
- **Local Market Power.** For 7 out of the top 10 congested facilities (by real-time binding hours), the number of suppliers providing constraint relief is three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.5 percent in the first six months of 2019 to 1.2 percent in the first six months of 2020. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.8 percent in the first six months of 2019 to 0.9 percent in the first six months of 2020. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

In the first six months of 2020, nine control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first six months of 2019 and 2020. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.0 percent in the first six months of 2019 and 2020.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** One unit qualified for an FMU adder for the months of September and October 2019 and two units qualified for an FMU adder in June 2020.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first six months of 2020, in the PJM Real-Time Energy Market, 99.5 percent of marginal units had offer prices less than $50 per MWh. While markups in the real-time market were generally low, some marginal units did have substantial markups. The highest markup for any marginal unit in the first six months of 2020 was more than $150 per MWh when using unadjusted cost based offers.

  In the first six months of 2020, in the PJM Day-Ahead Energy Market, 99.9 percent of marginal generating units had offer prices less than $50 per MWh. Markups in the day-ahead market were generally low. The highest markup for any marginal unit in the day-ahead market in the first six months of 2020 was about $80 per MWh.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for coal and gas fired units decreased in the first six months of 2020.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first six months of 2020, the unadjusted markup component of LMP was $0.34 per MWh or 1.8 percent of the PJM load-weighted, average LMP. June had the highest unadjusted peak markup component, $2.02 per MWh, or 8.2 percent of the real-time, peak hour load-weighted, average LMP. There were 17 hours in the first six months of 2020 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded the 99th percentile of the hourly markup contribution or $31.14 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first six months of 2020, the unadjusted markup component of LMP resulting from generation resources was -$0.14 per MWh or -0.7 percent of the PJM day-ahead load-weighted average LMP.

June had the highest unadjusted peak markup component, $0.39 per MWh.

Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 7.0 percent of marginal unit intervals in the first six months of 2020 the marginal unit had local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost

Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Adopted 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that market sellers not be allowed to designate any portion of an available capacity resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[3] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not

3 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[4] [5] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)

4 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

5 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2020, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average hourly real-time cleared generation decreased by 4,568 MWh, 5.0 percent, and peak load decreased by 6,141 MWh, 4.6 percent, in the first six months of 2020 compared to the first six months of 2019. Both the weather and COVID-19 played a role in this significant drop in demand. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[6] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. Many of these issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost to serve load at a given time. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first six months of 2020 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's reserve pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight, because PJM is not implementing scarcity pricing when there is scarcity. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage. There are significant issues with operator

6 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of RT SCED cases used for resource dispatch and the RT SCED cases used to calculate real-time prices. Alignment of resource dispatch with pricing and settlements requires reducing the RT SCED ramp time to five minutes to match the five minute settlement interval. PJM should fix its current operating practices and ensure consistency and transparency regarding approval of RT 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. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

The PJM defined inputs to the dispatch tools, particularly the real-time SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs prioritizes minimizing uplift over minimizing production costs. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. But without reducing the dispatch period from ten to five minutes, the new uplift payments will not correspond to following dispatch. The magnitude of the new payments and their effects on behavior are not well understood.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets:

revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first six months of 2020 or prior years. In the first six months of 2020, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 31.5 percent in 2016 to 70.1 percent in the first six months of 2020. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first six months of 2019. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first six months of 2020.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first six months of 2020, 436 MW of new resources were added in the energy market, and 1,932 MW of resources and 457 MW of pseudo ties were retired. Figure 3-1 shows the average hourly real-time supply curve and demand for the on peak hours in the spring of 2019-2020.[7] [8] [9] This figure reflects actual available MW from units that are online or offline and available

7 Real-time generation offers and real-time import MWh are included.
8 Real-time load and export MWh are included.
9 The spring supply curve period is from March 1 to May 31.

to generate power in one hour, and all units restricted by ramping capabilities. Figure 3-2 shows the typical dispatch range.

Figure 3-1 Average hourly real-time supply curve comparison: 2019 spring and 2020 spring

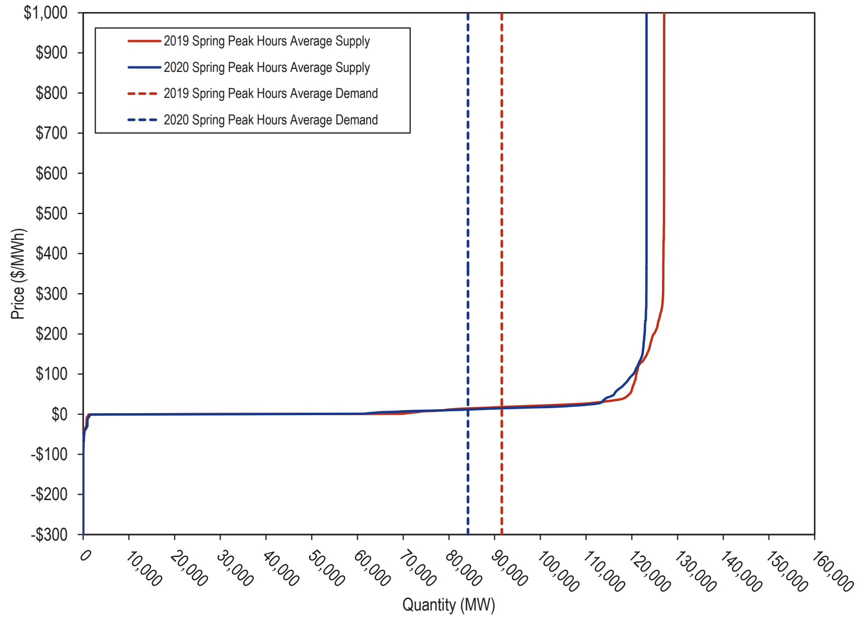


Figure 3-2 Typical dispatch range of average hourly spring real-time supply curves

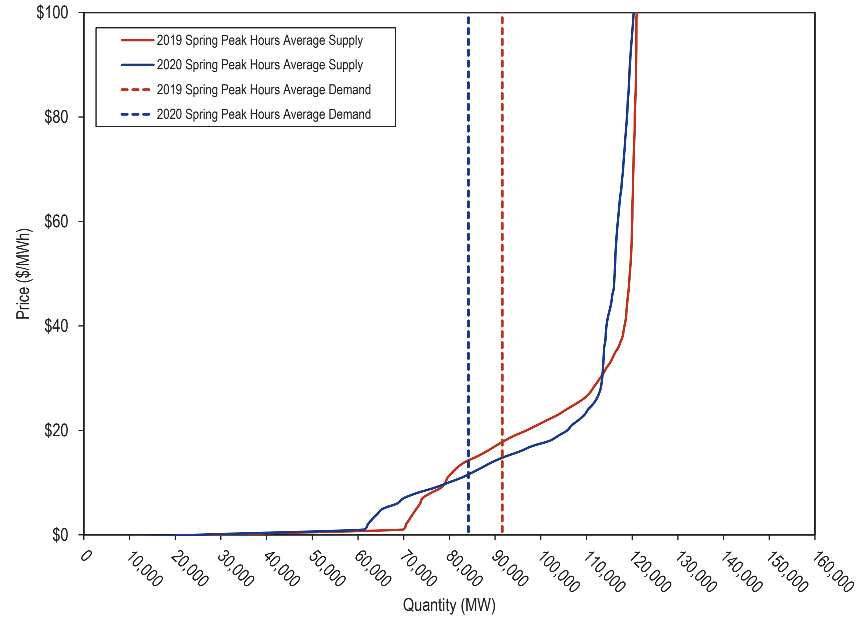


Table 3-2 shows the price elasticity of supply for the on peak hours in the 2019 and 2020 spring by load level. The price elasticity of supply measures the responsiveness of the quantity supplied (MWh) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

Supply is elastic when elasticity is greater than 1.0. This indicates that supply MW are relatively sensitive to changes in price. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the calculated elasticity is low throughout.

Table 3-2 Price Elasticity of Supply

	Elasticity of Supply	
GWh	2019 Spring	2020 Spring
Min - 75	0.015	0.032
75 - 95	0.200	0.317
95 - 115	0.271	0.105
115 - Max	0.003	0.003

Figure 3-3 is the PJM day-ahead generation aggregate supply curve, which includes day-ahead hourly supply for the on peak hours of the 2019 and 2020 spring.[10]

Figure 3-3 PJM day-ahead generation aggregate supply curve: 2019 and 2020 spring

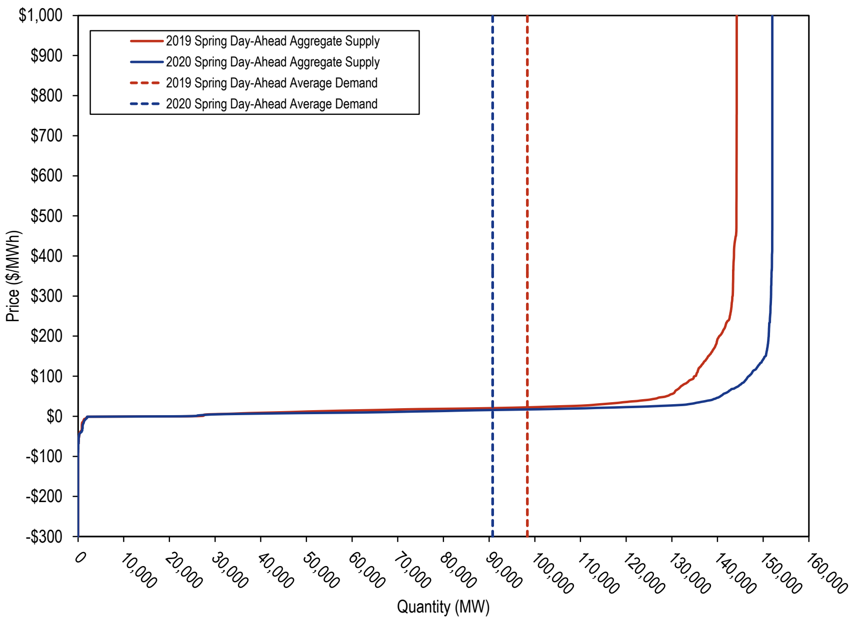
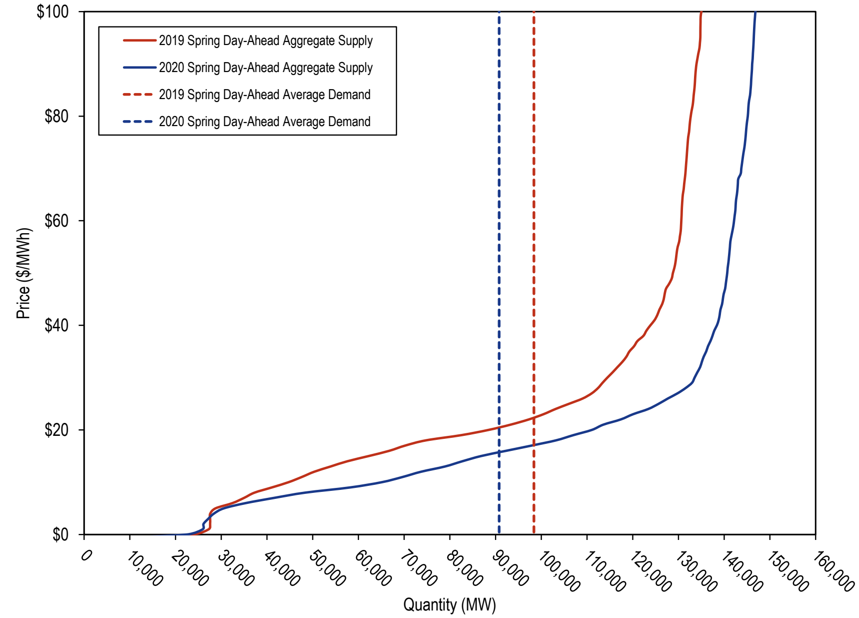


Figure 3-4 Typical dispatch range of average hourly spring day-ahead generation aggregate supply curves



Real-Time Supply

The maximum average on-peak hourly offered real-time supply was 123,217 MW for the 2020 spring and 127,128 MW for the 2019 spring. The available supply at a defined time is less than the total capacity of the PJM system because real-time supply at a defined time is restricted by unit ramp limits and start times.

PJM average hourly real-time cleared generation in the first six months of 2020 decreased by 5.0 percent from the first six months of 2019, from 91,613 MWh to 87,044 MWh.[11]

10 Day-ahead generation offers, INC offer MWh, day-ahead import MWh are included. UTCs are not included because UTCs do not offer at a price.

11 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

PJM average hourly real-time cleared supply including imports in the first six months of 2020 decreased by 5.5 percent from the first six months of 2019, from 92,947 MWh to 87,861 MWh.

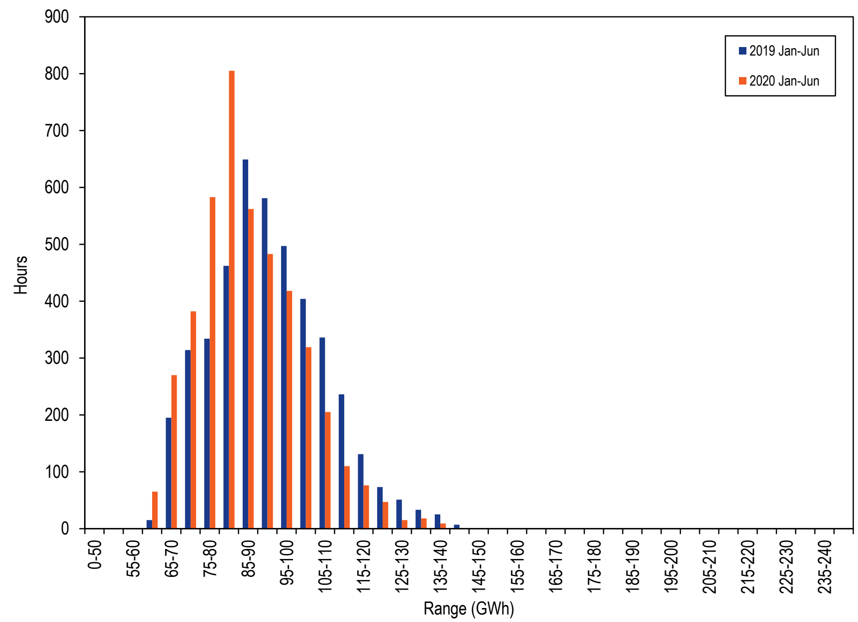
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Frequency

Figure 3-5 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2019 and 2020.

Figure 3-5 Distribution of real-time generation plus imports: January through June, 2019 and 2020[12]



12 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-3 shows real-time hourly supply summary statistics for the first six months of the 20 year period from 2001 through 2020.

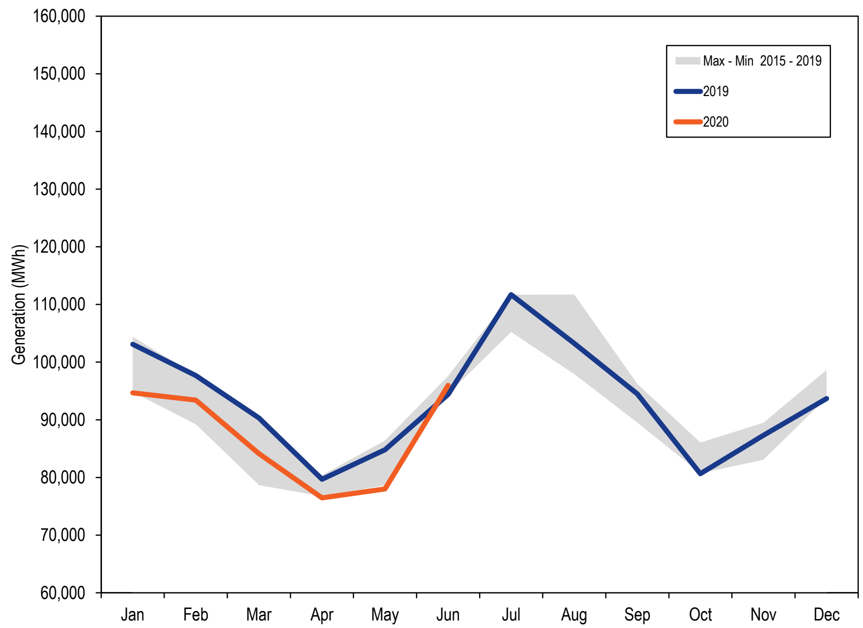
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through June, 2001 through 2020

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,428	4,679	32,412	4,813	NA	NA	NA	NA
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%
2016	86,335	14,576	91,218	15,231	(4.2%)	(9.1%)	(5.6%)	(11.3%)
2017	88,669	13,528	91,108	14,029	2.7%	(7.2%)	(0.1%)	(7.9%)
2018	91,631	14,828	94,091	15,312	3.3%	9.6%	3.3%	9.1%
2019	91,613	14,403	92,947	14,735	(0.0%)	(2.9%)	(1.2%)	(3.8%)
2020	87,044	13,308	87,861	13,453	(5.0%)	(7.6%)	(5.5%)	(8.7%)

PJM Real-Time, Monthly Average Generation

Figure 3-6 compares the real-time, monthly average hourly generation in 2019 and the first six months of 2020 with the historic five year range. As a result of weather and COVID-19, the monthly average hourly generation of the first six months of 2020 was lower than minimum of past five years in April and May.

Figure 3-6 Real-time monthly average hourly generation: January 2019 through June 2020



Day-Ahead Supply

PJM average hourly day-ahead cleared supply in the first six months of 2020, including INCs and up to congestion transactions, decreased by 5.5 percent from the first six months of 2019, from 115,511 MWh to 109,126 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in the first six months of 2020 decreased by 5.6 percent from the first six months of 2019, from 115,896 MWh to 109,369 MWh.

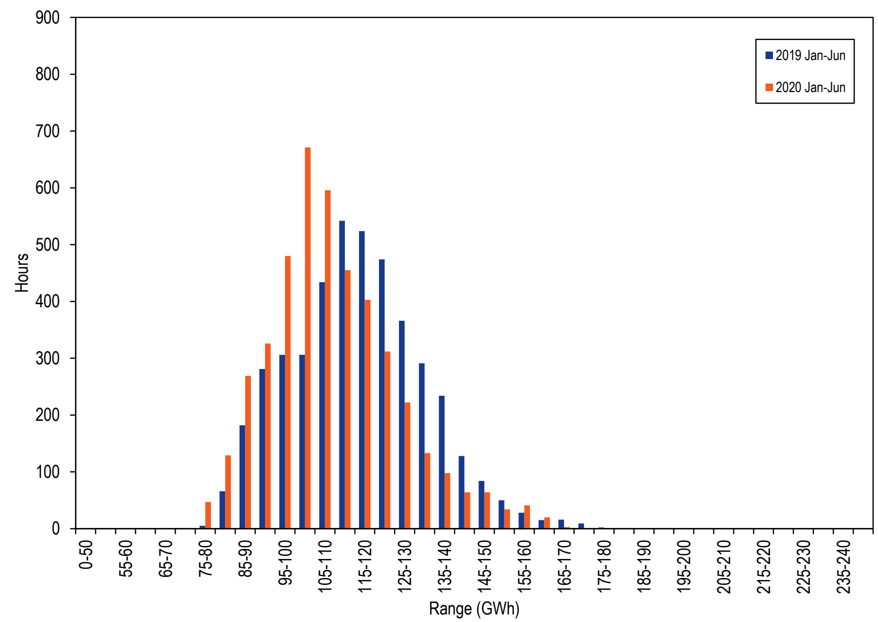
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-7 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for the first six months of 2019 and 2020.

Figure 3-7 Distribution of day-ahead supply plus imports: January through June, 2019 and 2020[13]



13 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly supply summary statistics for the first six months of the 20 year period from 2001 through 2020.

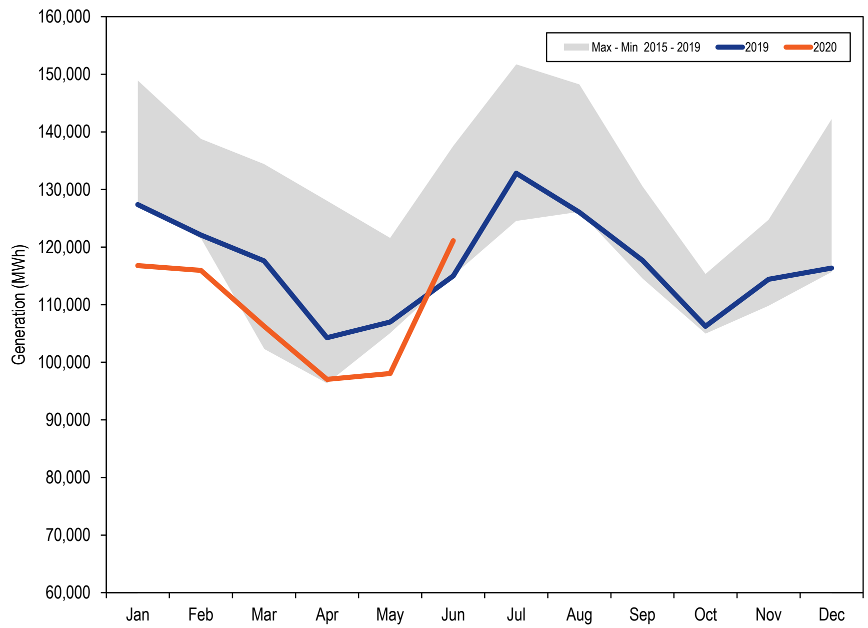
Table 3-4 Average hourly day-ahead supply and day-ahead supply plus imports: January through June, 2001 through 2020

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,796	4,305	27,540	4,382	NA	NA	NA	NA
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,150	18,851	117,613	18,996	(30.5%)	35.3%	(30.0%)	34.5%
2016	127,715	20,380	129,798	20,518	10.9%	8.1%	10.4%	8.0%
2017	133,601	19,109	134,433	19,293	4.6%	(6.2%)	3.6%	(6.0%)
2018	113,028	21,246	113,493	21,258	(15.4%)	11.2%	(15.6%)	10.2%
2019	115,511	16,792	115,896	16,811	2.2%	(21.0%)	2.1%	(20.9%)
2020	109,126	16,253	109,369	16,248	(5.5%)	(3.2%)	(5.6%)	(3.3%)

PJM Day-Ahead, Monthly Average Supply

Figure 3-8 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for the first six months of 2019 and 2020 with the historic five year range. In January, February and May of 2020, the average supply was lower than the minimum of the previous five years.

Figure 3-8 Day-ahead monthly average hourly supply: January 2019 through June 2020



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first six months of 2019 and 2020, for day-ahead and real-time supply. All data are cleared MWh. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first of these columns is the total physical day-ahead generation less the total physical real-time generation and the second of these columns is the total day-ahead supply less the total real-time supply.

Table 3-5 Day-ahead and real-time supply (MWh): January through June, 2019 and 2020

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Jun	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2019	91,791	2,977	20,744	385	115,896	91,613	92,947	178	22,949
	2020	87,013	2,562	19,551	243	109,369	87,044	87,861	(31)	21,508
Median	2019	90,724	2,852	20,543	337	115,388	90,442	91,752	282	23,636
	2020	84,934	2,513	19,408	225	107,105	84,894	85,598	40	21,507
Standard Deviation	2019	15,132	984	4,227	242	16,811	14,403	14,735	729	2,076
	2020	14,237	762	3,687	167	16,248	13,308	13,453	929	2,795
Peak Average	2019	99,802	3,456	21,918	342	125,518	98,954	100,338	848	25,180
	2020	94,576	2,818	20,509	217	118,121	93,707	94,552	869	23,568
Peak Median	2019	97,990	3,399	21,578	281	123,629	96,880	98,330	1,110	25,299
	2020	93,025	2,787	20,287	200	115,771	92,211	93,125	814	22,646
Peak Standard Deviation	2019	12,609	928	4,032	243	13,717	12,299	12,660	310	1,057
	2020	12,879	771	3,786	160	15,074	12,323	12,497	556	2,577
Off-Peak Average	2019	84,747	2,555	19,712	423	107,436	85,158	86,448	(411)	20,988
	2020	80,335	2,336	18,705	265	101,640	81,160	81,951	(825)	19,689
Off-Peak Median	2019	83,078	2,432	19,532	380	106,336	83,171	84,258	(93)	22,078
	2020	78,680	2,274	18,521	245	100,599	79,813	80,667	(1,132)	19,932
Off-Peak Standard Deviation	2019	13,583	827	4,125	236	14,585	12,955	13,300	629	1,285
	2020	11,838	677	3,379	169	13,006	11,207	11,335	631	1,671

Figure 3-9 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day for the first six months of 2020. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-9 Day-ahead and real-time supply (Average volumes by hour of the day): January through June, 2020

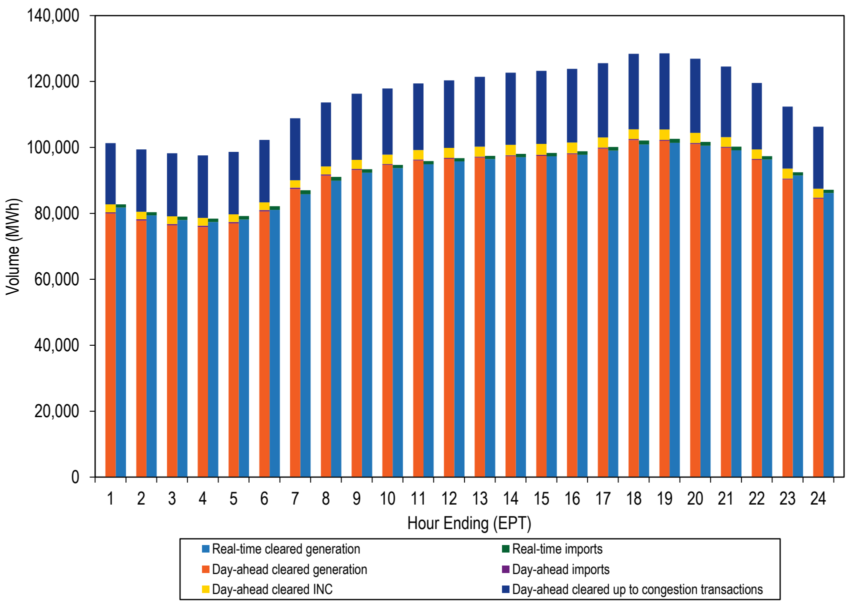
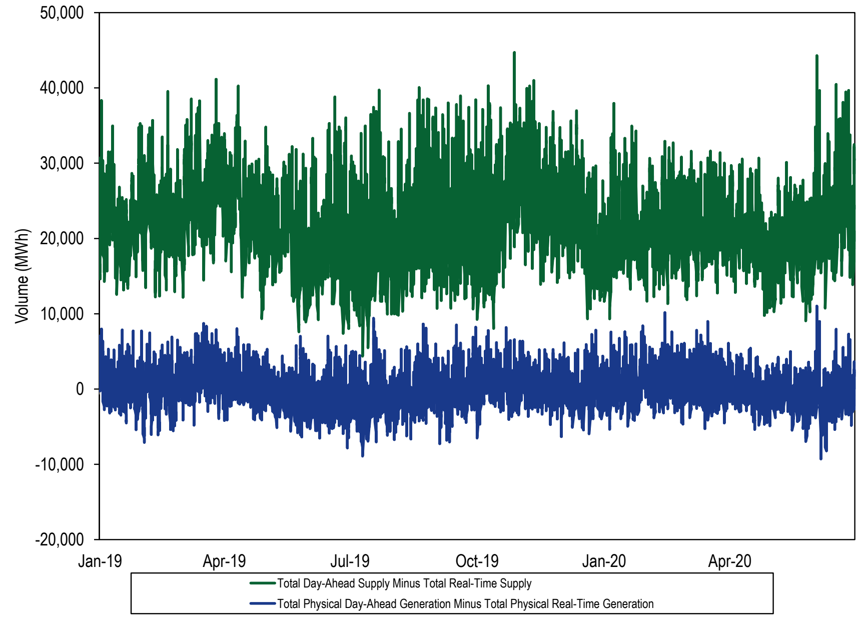


Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in 2019 and the first six months of 2020.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): January 2019 through June 2020



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and, in the day-ahead energy market, includes virtual transactions.[14]

The PJM system real-time hourly peak load in the first six months of 2020 was 127,919 MWh in the HE 1600 on June 10, 2020, which was 6,141 MWh, or 4.6 percent, less than the peak load in the first six months of 2019, 134,060 MWh in the HE 0800 on January 31, 2019.

Table 3-6 shows the peak loads for the first six months of 1999 through 2020.

Table 3-6 Actual footprint peak loads: January through June, 1999 through 2020[15 16]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MWh)	Annual Change (MWh)	Annual Change (%)
1999	Tue, June 08	17	48,447	NA	NA
2000	Mon, June 26	17	49,305	858	1.8%
2001	Thu, June 28	17	50,157	852	1.7%
2002	Wed, June 26	15	60,625	10,468	20.9%
2003	Thu, June 26	17	61,477	852	1.4%
2004	Wed, June 09	17	77,867	16,390	26.7%
2005	Tue, June 28	16	124,569	46,702	60.0%
2006	Tue, May 30	17	121,386	(3,183)	(2.6%)
2007	Wed, June 27	16	128,115	6,729	5.5%
2008	Mon, June 09	17	127,216	(900)	(0.7%)
2009	Fri, January 16	19	114,765	(12,451)	(9.8%)
2010	Wed, June 23	17	123,490	8,726	7.6%
2011	Wed, June 08	17	141,074	17,583	14.2%
2012	Wed, June 20	18	144,361	3,287	2.3%
2013	Tue, June 25	16	136,674	(7,687)	(5.3%)
2014	Tue, June 17	17	138,448	1,774	1.3%
2015	Fri, February 20	8	139,647	1,199	0.9%
2016	Mon, June 20	17	132,042	(7,606)	(5.4%)
2017	Mon, June 12	18	137,834	5,793	4.4%
2018	Mon, June 18	17	145,367	7,532	5.5%
2019	Thu, January 31	8	134,060	(11,307)	(7.8%)
2020	Wed, June 10	16	127,919	(6,141)	(4.6%)

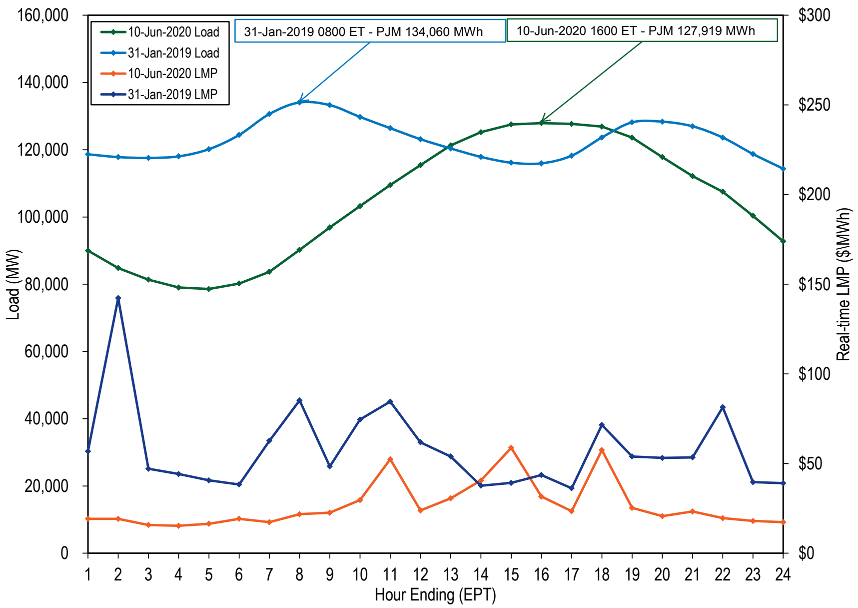
14 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

15 Peak loads shown are power accounting load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions," for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

16 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Figure 3-11 compares prices and load on the peak load days in the first six months of 2019 and 2020. The average real-time LMP for the June 10, 2020, peak load hour was $31.56 and for the January 31, 2019 peak load hour it was $85.21.

Figure 3-11 Peak load day comparison: Thursday, January 31, 2019 and Wednesday, June 10, 2020



Real-Time Demand

PJM average hourly real-time demand in the first six months of 2020 decreased by 5.8 percent from the first six months of 2019, from 86,297 MWh to 81,255 MWh.[17] PJM average hourly real-time demand including exports in the first six months of 2020 decreased by 5.4 percent from the first six months of 2019, from 91,262 MWh to 86,344 MWh. Both the weather and COVID-19 played a role in this significant drop in demand.

17 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

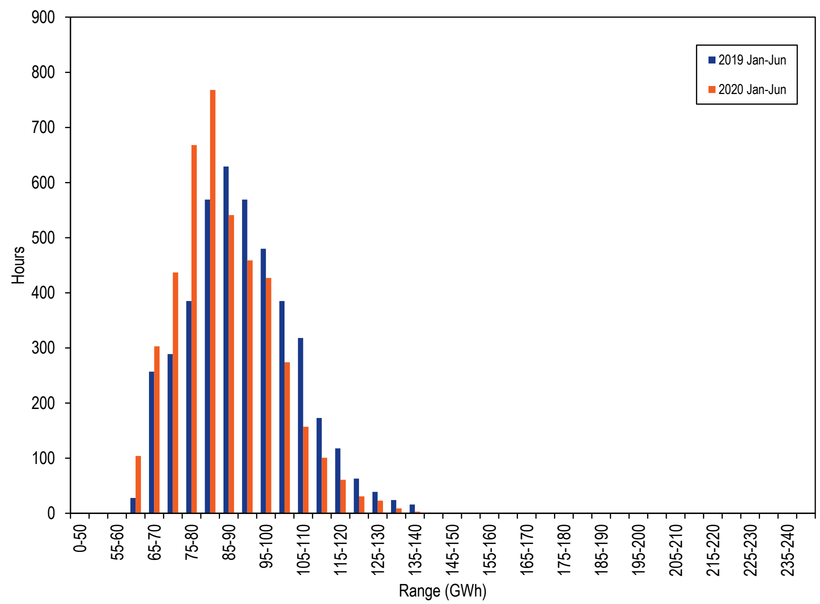
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority's checkout process.

PJM Real-Time Demand Duration

Figure 3-12 shows the distribution of hourly PJM real-time load plus exports for the first six months of 2019 and 2020.[18]

Figure 3-12 Distribution of real-time accounting load plus exports: January through June, 2019 and 2020[19]



18 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

19 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first six months of 2001 through 2020.[20] Real-time load in the first six months of 2020, reached its lowest level for the comparable period since 2011.

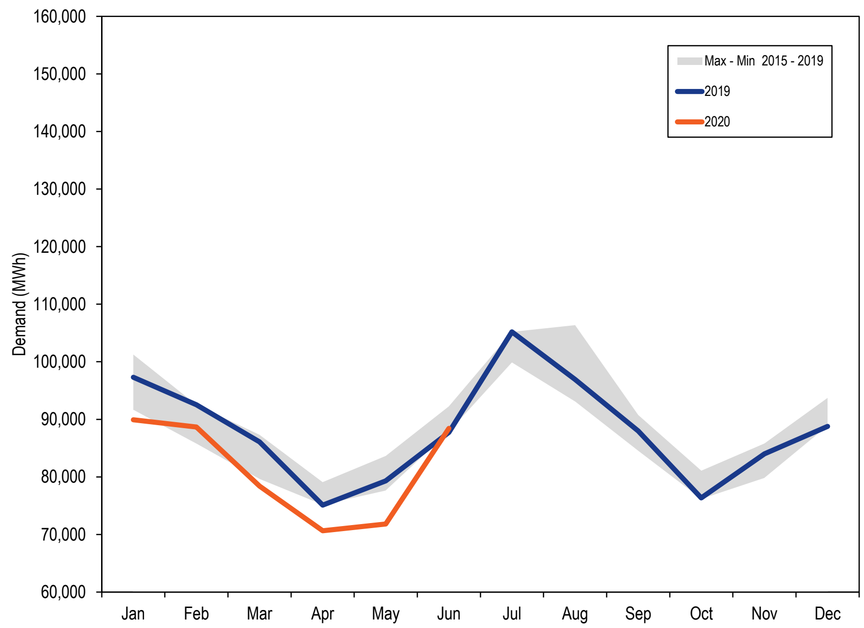
Table 3-7 Real-time load and real-time load plus exports: January through June, 2001 through 2020

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,180	5,274	32,041	5,103	NA	NA	NA	NA
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%
2016	85,800	14,517	89,746	14,798	(5.3%)	(10.3%)	(5.3%)	(10.8%)
2017	84,569	13,670	89,477	13,638	(1.4%)	(5.8%)	(0.3%)	(7.8%)
2018	88,847	14,683	92,352	14,818	5.1%	7.4%	3.2%	8.7%
2019	86,297	14,038	91,262	14,303	(2.9%)	(4.4%)	(1.2%)	(3.5%)
2020	81,255	13,191	86,344	13,133	(5.8%)	(6.0%)	(5.4%)	(8.2%)

PJM Real-Time, Monthly Average Load

Figure 3-13 compares the real-time, monthly average loads in 2019 and the first six months of 2020, with the historic five year range. The monthly average loads in the first six months of 2020, were lower than the minimum of the past five years in January, March, April and May.

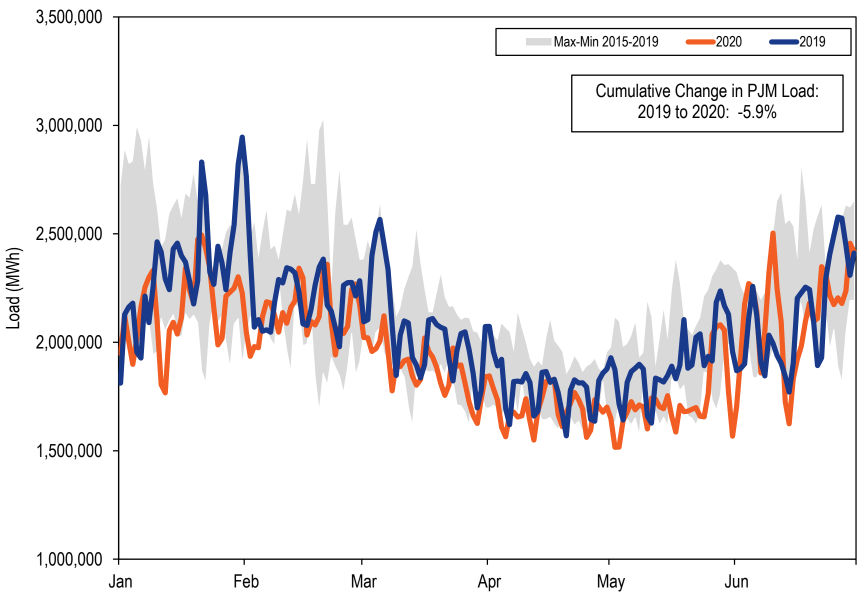
Figure 3-13 Real-time monthly average hourly load: January 2019 through June 2020



20 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

Figure 3-14 compares the real-time, average daily loads in 2019 and the first six months of 2020, with the historic five year range. On a cumulative basis, real-time daily load declined by 5.9 percent in the first six months of 2020 compared to the first six months of 2019.

Figure 3-14 Real-time daily load: January through June, 2019 and 2020



PJM real-time load is significantly affected by weather conditions. Table 3-8 compares the PJM monthly heating and cooling degree days in 2019 and the first six months of 2020.[21] Heating degree days decreased 10.7 percent compared to the first six months of 2019. Cooling degree days increased 7.2 percent compared to the first six months of 2019.

Table 3-8 Heating and cooling degree days: January 2019 through June 2020

	2019		2020		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	909	0	698	0	(23.3%)	0.0%
Feb	688	0	652	0	(5.2%)	0.0%
Mar	607	0	385	0	(36.6%)	0.0%
Apr	145	0	279	0	92.1%	0.0%
May	23	90	105	59	363.0%	(33.9%)
Jun	0	210	0	262	0.0%	24.9%
Jul	0	423				
Aug	0	312				
Sep	0	211				
Oct	100	31				
Nov	576	0				
Dec	675	0				
Jan-Jun	2,372	299	2,118	321	(10.7%)	7.2%

PJM real-time load was generally lower in the first six months of 2020 than in the first six months of 2019, and, in spring 2020, was frequently lower than the minimum of the past 5 years. The weather and the COVID-19 lockdown order both contributed to the result.

Figure 3-15 and Figure 3-16 shows the real-time daily load and the weather normalized load for 2019 and the first six months of 2020.

Weather normalized load is calculated using the historic relationship between PJM daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-15 shows that the weather normalized load is very close to actual load under the normal market conditions in 2019. Figure 3-16 shows that from March through May 2020, the actual load was significantly less than the weather normalized load. The difference was the impact of changes in the pattern and level of activity as a result of COVID-19 and associated policy responses.

21 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-15 Real-time daily load and weather normalized load: 2019

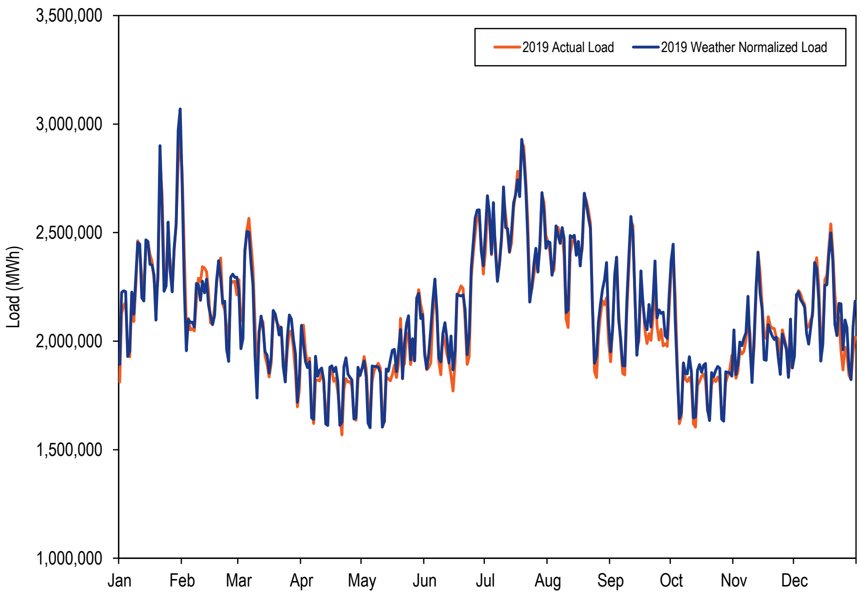
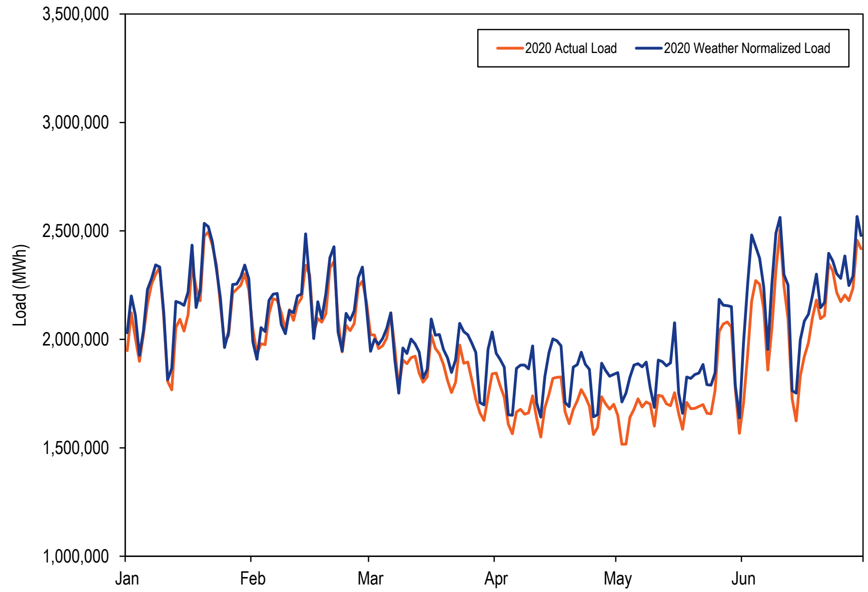


Figure 3-16 Real-time daily load and weather normalized load: January through June, 2020



Day-Ahead Demand

PJM average hourly day-ahead demand in the first six months of 2020, including DECs and up to congestion transactions, decreased by 6.1 percent from the first six months of 2019, from 110,890 MWh to 104,164 MWh. When exports are added, PJM average hourly day-ahead demand in the first six months of 2020 decreased by 5.7 percent from the first six months of 2019, from 113,738 MWh to 107,293 MWh.

In the PJM Day-Ahead Energy Market, five types of financially binding demand bids are made and cleared:

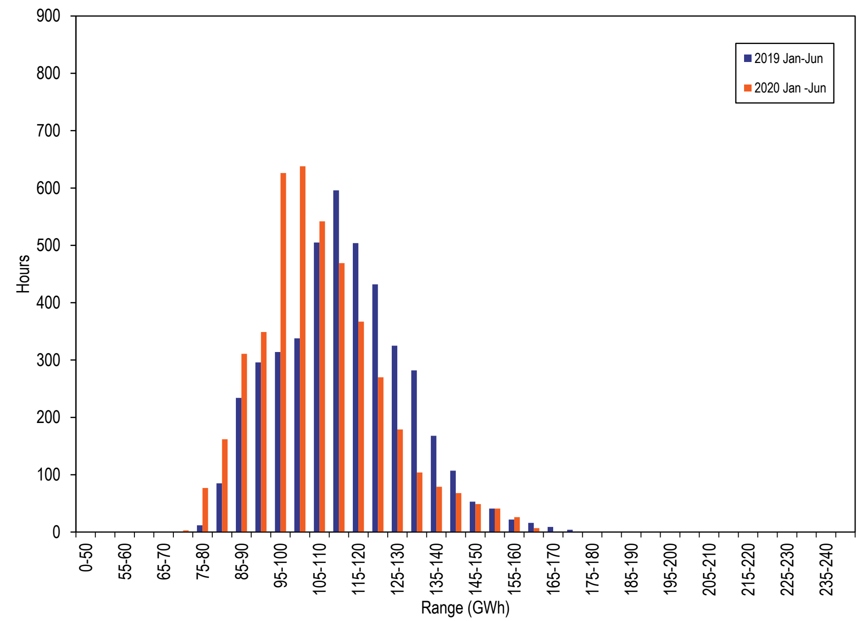
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM day-ahead demand is the total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-17 shows the hourly distribution of PJM day-ahead demand for the first six months of 2019 and 2020.

Figure 3-17 Distribution of day-ahead demand plus exports: January through June, 2019 and 2020[22]



22 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-9 presents day-ahead hourly demand summary statistics for the first six months of 2001 through 2020.

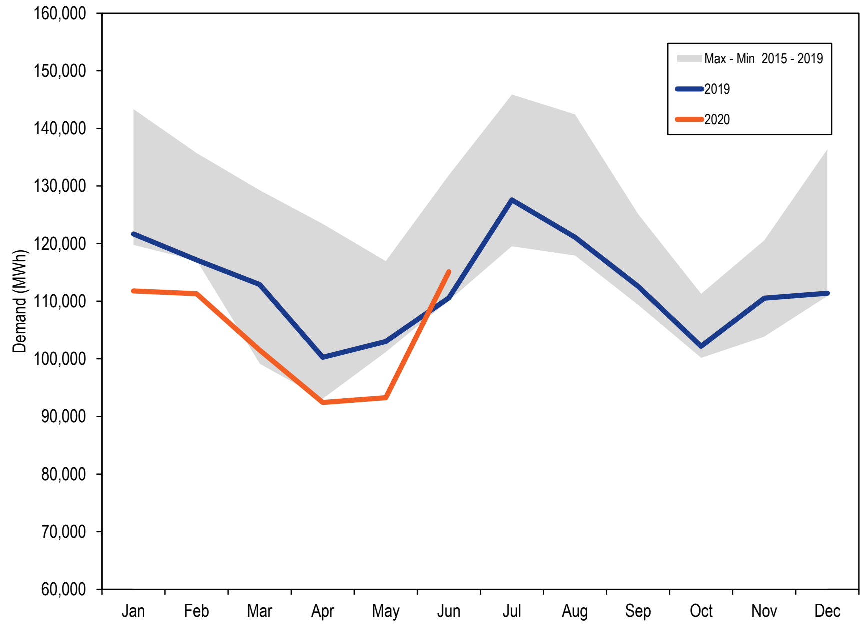
Table 3-9 Average hourly day-ahead demand and day-ahead demand plus exports: January through June, 2001 through 2020

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	32,425	6,014	33,075	5,857	NA	NA	NA	NA
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,750	18,076	115,117	18,477	(30.5%)	30.3%	(30.1%)	33.9%
2016	124,542	19,750	127,461	19,991	11.4%	9.3%	10.7%	8.2%
2017	128,690	18,440	131,976	18,746	3.3%	(6.6%)	3.5%	(6.2%)
2018	108,950	20,548	111,451	20,718	(15.3%)	11.4%	(15.6%)	10.5%
2019	110,890	15,994	113,738	16,323	1.8%	(22.2%)	2.1%	(21.2%)
2020	104,164	15,680	107,293	15,845	(6.1%)	(2.0%)	(5.7%)	(2.9%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2019 and first six months of 2020 with the historic five-year range.

Figure 3-18 Day-ahead monthly average hourly demand: January 2019 through June 2020



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for the first six months of 2019 and 2020 day-ahead and real-time demand. All data are cleared MWh. The last two columns of Table 3-10 are the day-ahead demand minus the real-time demand: the first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load; and the second column is the total day-ahead demand less the total real-time demand.

Table 3-10 Cleared day-ahead and real-time demand (MWh): January through June, 2019 and 2020

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Jun	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2019	85,105	1,309	3,732	20,744	2,848	113,738	86,297	91,262	117	22,476
	2020	79,908	1,099	3,606	19,551	3,129	107,293	81,255	86,344	(248)	20,950
Median	2019	84,476	1,332	3,442	20,543	2,684	113,286	85,281	90,128	527	23,158
	2020	78,276	1,112	3,186	19,408	3,121	105,117	79,059	84,151	329	20,967
Standard Deviation	2019	13,536	248	1,486	4,227	828	16,323	14,038	14,303	(255)	2,019
	2020	12,832	226	1,864	3,687	687	15,845	13,191	13,133	(133)	2,712
Peak Average	2019	92,735	1,427	4,089	21,918	2,962	123,130	93,495	98,505	668	24,626
	2020	86,653	1,199	4,277	20,509	3,225	115,864	87,790	92,884	62	22,980
Peak Median	2019	91,389	1,449	3,845	21,578	2,837	121,290	91,582	96,586	1,256	24,705
	2020	86,061	1,233	3,878	20,287	3,200	113,650	86,855	91,479	438	22,172
Peak Standard Deviation	2019	10,950	242	1,528	4,032	859	13,305	11,852	12,257	(661)	1,048
	2020	11,337	247	2,038	3,786	682	14,672	12,120	12,195	(536)	2,477
Off-Peak Average	2019	78,396	1,205	3,418	19,712	2,749	105,480	79,969	84,894	(367)	20,586
	2020	73,950	1,011	3,014	18,705	3,044	99,724	75,484	80,567	(523)	19,157
Off-Peak Median	2019	77,303	1,219	3,176	19,532	2,585	104,374	78,225	82,839	297	21,534
	2020	72,546	1,027	2,721	18,521	3,044	98,774	74,111	79,275	(538)	19,500
Off-Peak Standard Deviation	2019	11,947	202	1,374	4,125	786	14,118	12,700	12,874	(550)	1,244
	2020	10,997	161	1,458	3,379	681	12,672	11,268	11,061	(111)	1,610

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first six months of 2020. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-19 Day-ahead and real-time demand (Average hourly volumes): January through June, 2020

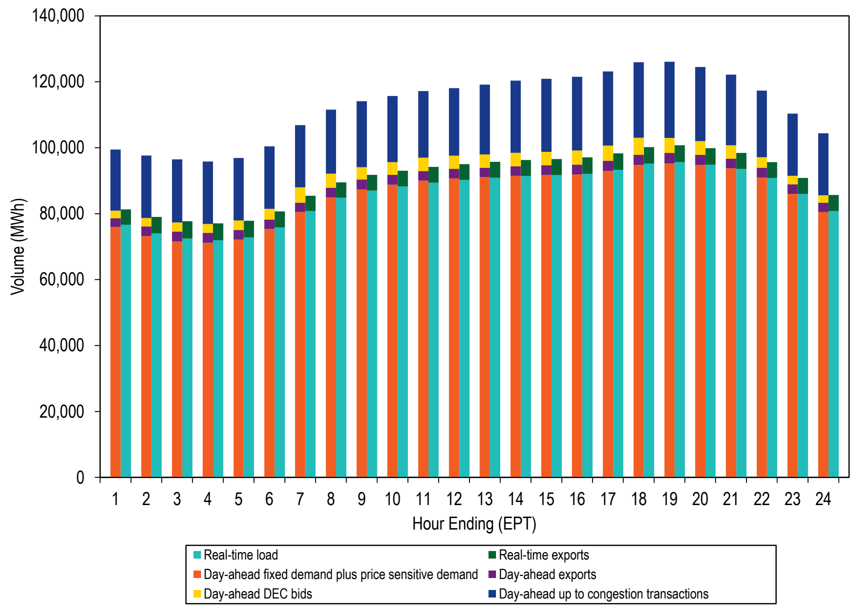
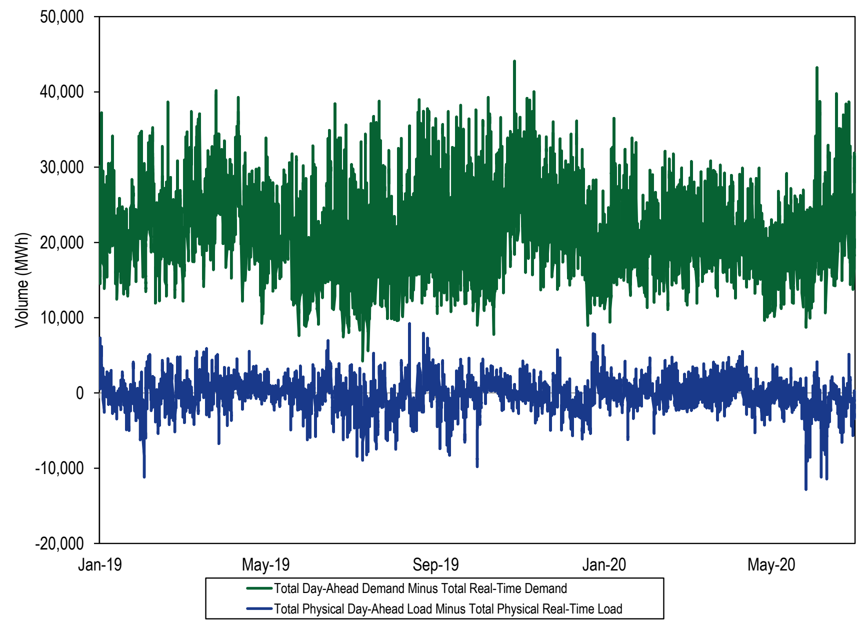


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand for 2019 and the first six months of 2020.

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): 2019 through June 2020



Market Behavior

Supply and Demand: Load and Spot Market

Participants in the PJM Real-Time and Day-Ahead Energy Markets can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Load is served by a combination of self supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through InSchedule transactions referred to as wholesale load responsibility (WLR), retail load responsibility (RLR) transactions and generation responsibility. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self supply) means that the parent company is generating power from plants that it owns. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the real-time and day-ahead energy markets for each hour.

Real-Time Load and Spot Market

Table 3-11 shows the monthly average share of real-time load served by each parent company's self supply, bilateral contracts and spot purchases in the first six months of 2019 and 2020. In the first six months of 2020, 16.8 percent of real-time load was supplied by bilateral contracts, 23.2 percent by spot market purchase and 60.0 percent by self supply. Compared with the first six months of 2019, reliance on bilateral contracts increased by 1.2 percentage points, reliance on spot supply decreased by 1.7 percentage points and reliance on self supply increased by 0.5 percentage points.

Table 3-11 Sources of real-time supply: January 2019 through June 2020[23]

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	15.4%	23.9%	60.7%	17.1%	24.7%	58.2%	1.7%	0.8%	(2.5%)
Feb	15.4%	25.2%	59.4%	16.6%	23.8%	59.6%	1.2%	(1.3%)	0.1%
Mar	15.2%	27.5%	57.4%	16.9%	23.8%	59.3%	1.8%	(3.7%)	2.0%
Apr	16.7%	24.8%	58.5%	17.2%	21.5%	61.3%	0.4%	(3.3%)	2.9%
May	16.0%	24.3%	59.7%	17.2%	21.6%	61.1%	1.2%	(2.6%)	1.5%
Jun	15.0%	23.8%	61.1%	15.9%	23.3%	60.7%	0.9%	(0.5%)	(0.4%)
Jul	14.4%	23.8%	61.8%						
Aug	15.3%	24.1%	60.6%						
Sep	15.5%	25.5%	58.9%						
Oct	16.7%	27.7%	55.6%						
Nov	15.7%	28.6%	55.6%						
Dec	19.8%	22.6%	57.6%						
Jan-Jun	15.6%	24.9%	59.5%	16.8%	23.2%	60.0%	1.2%	(1.7%)	0.5%

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can use not only their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but also virtual resources to meet their load serving

23 Table 3-11 and Table 3-12 were calculated as of July 16, 2020. The values may change slightly as billing values are updated by PJM.

obligations in the day-ahead market in any hour. Virtual supply is treated as supply in the day-ahead market and virtual demand is treated as demand in the day-ahead market.

Table 3-12 shows the monthly average share of day-ahead demand served by each parent company's self supply, bilateral contracts and spot purchases in the first six months of 2019 and 2020. In the first six months of 2020, 15.8 percent of day-ahead demand was supplied by bilateral contracts, 23.6 percent by spot market purchases and 60.6 percent by self supply. Compared with the first six months of 2019, reliance on bilateral contracts increased by 1.1 percentage points, reliance on spot supply decreased by 1.5 percentage points, and reliance on self supply increased by 0.4 percentage points.

Table 3-12 Sources of day-ahead supply: January through June, 2019 and 2020

	2019			2020			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.5%	24.0%	61.5%	16.2%	24.5%	59.3%	1.6%	0.5%	(2.1%)
Feb	14.6%	24.9%	60.5%	15.6%	23.5%	60.9%	1.0%	(1.4%)	0.5%
Mar	14.3%	27.2%	58.5%	15.7%	24.0%	60.3%	1.4%	(3.3%)	1.9%
Apr	15.8%	25.2%	59.0%	16.2%	22.5%	61.3%	0.3%	(2.7%)	2.4%
May	14.8%	25.2%	60.0%	16.1%	22.8%	61.1%	1.3%	(2.4%)	1.1%
Jun	14.2%	24.4%	61.4%	15.1%	24.1%	60.8%	0.9%	(0.3%)	(0.5%)
Jul	13.9%	23.8%	62.3%						
Aug	14.7%	24.2%	61.1%						
Sep	14.8%	25.9%	59.3%						
Oct	15.9%	27.8%	56.3%						
Nov	14.9%	28.2%	56.8%						
Dec	19.0%	22.3%	58.7%						
Jan-Jun	14.7%	25.1%	60.2%	15.8%	23.6%	60.6%	1.1%	(1.5%)	0.4%

Generator Offers

Generator offers are categorized as pool scheduled (Table 3-13) or self scheduled (Table 3-14).[24] Units which are available for economic dispatch are pool scheduled. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-13 and Table 3-14 do not include units that did not indicate their offer status or units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered above the economic range of a unit are categorized as emergency MW. Emergency MW offered above the self scheduled or dispatchable MW are included in both tables. Generators may have multiple available offers. In order to select one offer, if there are active emergency conditions, a PLS offer is used. If there is no active emergency, the lowest price-based offer is used. If there is no price-based offer, a cost-based offer is used, and if there are multiple cost-based offers, the lowest commitment cost offer is used.

Table 3-13 shows the proportion of day-ahead MW offered by pool scheduled units, by unit type and by offer price range, in the first six months of 2020. Pool scheduled units offer with an economic commitment status. For example, 41.7 percent of all CC offer MW were the economic minimum offered MW, and 37.6 percent of CC offer MW were dispatchable and in the $0 to $200 per MWh offer price range. The total column is the proportion of all MW offers by unit type that were dispatchable, including the economic minimum and emergency MW. For example, 83.5 percent of all CC unit offers were pool scheduled, including the 41.7 percent of economic minimum MW and 4.1 percent of emergency MW offered by CC units. The dispatchable range of a unit is between the economic minimum and emergency range. For example, 37.7 percent of all CC unit offers have an economic dispatch range. The all pool scheduled offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 25.9 percent of all pool scheduled offers were in the $0 to $200 per MWh price range. The total column in the all pool scheduled offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first six months of 2020, 28.7 percent of all pool scheduled offers had an economic dispatch range.

24 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number of owners and the small number of units.

Table 3-13 Distribution of day-ahead MW for pool scheduled unit offer prices: January through June, 2020

		Dispatchable (Range)							
Unit Type	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	41.7%	0.0%	37.6%	0.1%	0.0%	0.0%	0.0%	4.1%	83.5%
CT	63.0%	0.0%	27.7%	1.0%	0.2%	0.0%	0.0%	7.2%	99.2%
Diesel	39.0%	0.0%	19.7%	2.7%	0.0%	0.0%	0.0%	16.0%	77.4%
Nuclear	7.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%
Pumped Storage	0.0%	0.0%	5.9%	0.0%	0.0%	0.0%	0.0%	41.7%	47.6%
Run of River	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	0.1%	0.0%	13.6%	0.0%	0.0%	0.0%	0.0%	0.0%	13.7%
Steam - Coal	23.5%	0.0%	29.8%	0.0%	0.0%	0.0%	0.0%	1.6%	54.8%
Steam - Other	32.3%	0.0%	51.1%	1.7%	0.0%	0.0%	0.0%	3.1%	88.2%
Wind	1.1%	0.0%	7.9%	0.0%	0.0%	0.0%	0.0%	1.1%	10.1%
All Pool Scheduled Offers	31.7%	0.0%	25.9%	0.3%	0.0%	0.0%	0.0%	4.3%	64.7%

Table 3-14 shows the proportion of day-ahead offered MW by unit type that were self scheduled, and that were self scheduled and dispatchable by price range, for the first six months of 2020. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output or are self scheduled and dispatchable. For example, 16.5 percent of all CC offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.1 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 14.2 percent of all offers and self scheduled and dispatchable units accounted for 20.0 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW.

Table 3-14 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: January through June, 2020

	Self Scheduled		Self Scheduled and Dispatchable (Range)								
Unit Type	Must Run	Emergency	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.2%	0.1%	8.4%	0.0%	6.6%	0.0%	0.0%	0.0%	0.0%	1.1%	16.5%
CT	0.2%	0.1%	0.4%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%
Diesel	13.4%	4.0%	1.8%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	20.4%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	63.5%	0.0%	23.4%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	89.2%
Pumped Storage	4.0%	6.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.4%
Run of River	82.4%	16.9%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	99.7%
Solar	12.1%	8.2%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	21.1%
Steam - Coal	1.8%	0.6%	19.9%	0.0%	20.7%	0.0%	0.0%	0.0%	0.0%	2.1%	45.1%
Steam - Other	2.3%	0.3%	4.4%	0.0%	1.9%	0.1%	0.0%	0.0%	0.0%	0.6%	9.7%
Wind	5.0%	5.0%	2.3%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	2.3%	15.5%
All Self-Scheduled Offers	13.5%	0.7%	11.7%	0.0%	7.3%	0.0%	0.0%	0.0%	0.0%	0.9%	35.3%

Hourly Offers and Intraday Offer Updates

All participants are able to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can only make updates if their Fuel Cost Policy defines the intraday offer update process. Table 3-15 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first six months of 2020, an average of 302 units made hourly offers per day, an increase of 9 units from the first six months of 2019. In the first six months of 2020, 385 units opted in for intraday offer updates, an increase of 19 units from the first six months of 2019. In the first six months of 2020, an average of 131 units made intraday offer updates each day, a decrease of 12 units from the first six months of 2019.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through June, 2019 and 2020

	Fuel Type	2019	2020	Difference
Hourly Offers	Natural Gas	276	284	8
	Other Fuels	20	18	(2)
	Total	296	302	6
Opt In	Natural Gas	329	339	10
	Other Fuels	37	47	10
	Total	366	385	19
Intraday Offer Updates	Natural Gas	137	125	(12)
	Other Fuels	7	7	0
	Total	144	131	(12)

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. For the 2020/2021 Delivery Year, PJM procured only capacity performance resources. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions.[25] Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power.

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first six months of 2020. Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 35.6 percent of unit hours for units that failed the TPS test were committed on their price-based schedules that were less flexible than their cost based schedules.

25 *See* Protest of the Independent Market Monitor for PJM, Docket No. ER20-995 (February 25, 2020).

Table 3-16 Parameter mitigation for units failing TPS test: January through June, 2020

Day-ahead commitment for units that failed TPS test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	17,013	35.6%
Committed on price schedule as flexible as cost	4,469	9.4%
Total committed on price schedule without parameter limits	21,482	45.0%
Committed on cost (cost capped)	26,064	54.6%
Committed on price PLS	203	0.4%
Total committed on PLS schedules (cost or price PLS)	26,267	55.0%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold or hot weather alert was declared in the first six months of 2020. PJM declared cold weather alerts on three days and hot weather alerts on two days in the first six months of 2020.[26] The analysis includes units with a CP commitment in the zones where the cold and hot weather alerts were declared. Base capacity resources are subject to commitment on the price PLS schedule during hot weather alerts and not during cold weather alerts. Table 3-17 shows that 31.1 percent of unit hours in the day-ahead energy market were committed on price based schedules that were less flexible than their price PLS schedules.

Table 3-17 Parameter mitigation during weather alerts: January through June, 2020

Day-ahead commitment during hot and cold weather alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	2,624	31.1%
Committed on price schedule as flexible as PLS	2,508	29.7%
Total committed on price schedule without parameter limits	5,132	60.9%
Committed on cost (cost capped)	68	0.8%
Committed on price PLS	3,233	38.3%
Total committed on PLS schedules (cost or price PLS)	3,301	39.1%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. This recommendation would ensure that market power that results from inflexible parameters is mitigated during high load conditions and when a market seller fails the TPS test, consistent with the goal of having parameter limited schedules.

Parameter Limits

Beginning in the 2016/2017 Delivery Year, resources that had capacity performance (CP) commitments were required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments were also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, and base capacity resources beginning June 1, 2018, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance and base capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

26 *2020 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, at Emergency Procedures.

Beginning June 1, 2018, all RPM procured capacity resources were either capacity performance or base capacity resources. Entities that elected the fixed resource requirement (FRR) option were allowed to procure the legacy annual capacity product for the 2018/2019 Delivery Year. Beginning June 1, 2019, all capacity resources, including resources in FRR capacity plans, are either capacity performance or base capacity resources. Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance and base capacity resources, by submitting supporting documentation, which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources and base capacity resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[27] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-18 shows, for the delivery year beginning June 1, 2020, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM. Table 3-18 shows that 85.3 percent of subcritical coal steam units and 88.4 percent of supercritical coal steam units had an adjustment approved to one or more parameter limits from the default limits published by PJM, while only 31.6 percent of combined cycle units, and 35.0 percent of frame combustion turbine units, and 24.2 percent of aero derivative combustion turbine units had an adjustment approved to one or more parameter limits from the default limits published by PJM.

Table 3-18 Adjusted unit specific parameter limit statistics: Delivery Year 2020/2021

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	125	40	24.2%
Frame CT	178	96	35.0%
Combined Cycle	80	37	31.6%
Reciprocating Internal Combustion Engines	68	3	4.2%
Solid Fuel NUG	36	6	14.3%
Oil and Gas Steam	10	15	60.0%
Subcritical Coal Steam	10	58	85.3%
Supercritical Coal Steam	5	38	88.4%
Pumped Storage	10	0	0.0%

27 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

Real-Time Values

The MMU recommends that PJM market rules recognize the difference between operational parameters that indicate to PJM operators what a unit is capable of during the operating day and the parameters that result in uplift payments. The parameters provided to PJM operators each day should reflect what units are physically capable of so that operators can operate the system. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct and the assignment of performance risk to generation owners. PJM implemented the real-time value variable in Markets Gateway to address this, but there are problems with the implementation.

PJM market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real-time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the market seller can justify such operation based on an actual constraint.[28]

In practice, real-time values are generally used to communicate lower Turn Down Ratios which result from reduced Economic Max MW due to a derate (partial outage) on a unit, or from a requirement to operate at a defined output for equipment tests, environmental tests, or inspections. The RTV functionality allows units to communicate accurate short term operational parameters to PJM without requiring PJM customers to pay additional uplift charges, if the unit operates out of the money for routine tests and inspections. However, using real-time values to extend the time to start parameters (startup times and notification times) or minimum run time or minimum down time is inconsistent with the goal of real-time values. The protection offered by making units ineligible for uplift is only effective if the unit is committed and operated out of the money because of the RTVs. In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed at all, and may prohibit unit commitment in real time, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

28 See PJM Operating Agreement, Schedule 1, Section 3.2.3 (e).

The use of real-time values to extend startup times, notification times, minimum run time and minimum down time allows generators to circumvent the parameter limited schedule rules, to avoid commitment by PJM. Using RTVs to remove a unit from the real-time look-ahead dispatch window, and avoid commitment is withholding. These concerns are exacerbated if these units can otherwise provide relief to transmission constraints, and can provide flexibility to meet peak demand conditions. Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and offers to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses real-time values to communicate the longer time to start to PJM, there is currently no consequence to the market seller.

The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined justifications.

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[29] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[30] The Commission directed PJM to submit tariff language

29 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
30 *Id* at P 439.

to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[31]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties, who may be affiliates or have market power. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the reference resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter

31 *Id* at P 440.

limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. In the first six months of 2020, there were eight units in PJM that experienced gas pipeline restrictions leading to requests for 24 hour minimum run time on their parameter limited schedules.

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service procured by the generator.

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[32] Up to congestion transactions may be submitted between any two buses on a list of 49 buses eligible for up to congestion transaction bidding.[33] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

32 162 FERC ¶ 61,139.

33 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*," <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 3-21 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2020.

Figure 3-21 Day-ahead aggregate supply curves: 2020 example day

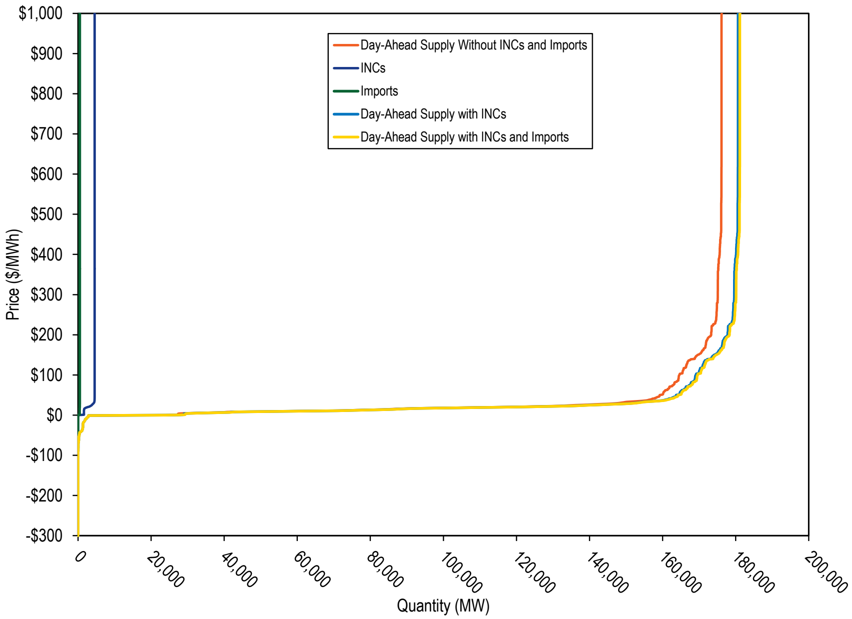


Figure 3-22 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-22 Typical dispatch price range for day-ahead aggregate supply curves: 2020 example day

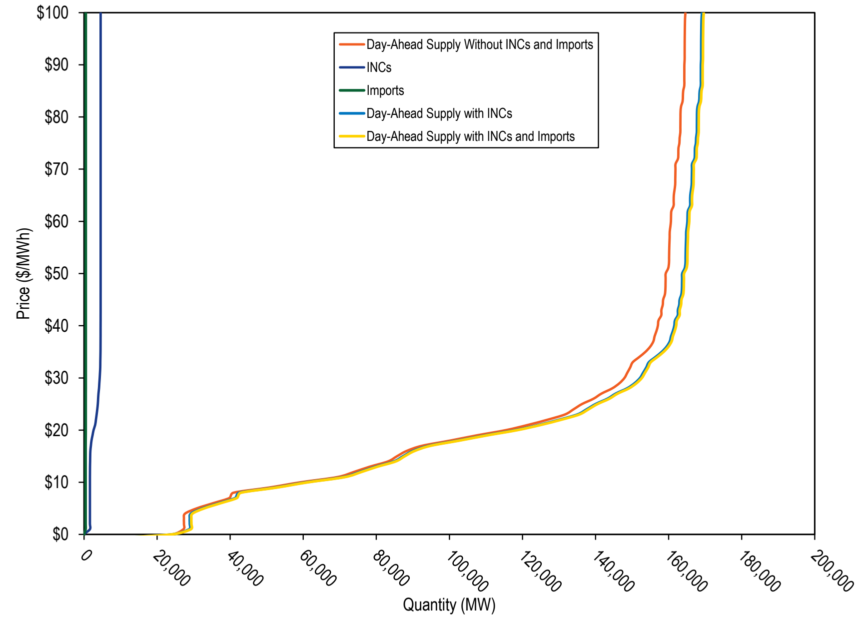


Table 3-19 shows the hourly average number of cleared and submitted increment offers and decrement bids by month from January 2019 through June 2020. The hourly average submitted MW increased by 14.0 percent and cleared increment MW decreased by 13.4 percent, from 6,199 MW and 2,960 MW in the first six months of 2019 to 7,064 MW and 2,562 MW in the first six months of 2020. The hourly average submitted MW increased by 15.6 percent and cleared decrement MW decreased by 2.8 percent, from 6,718 MW and 3,711 MW in the first six months of 2019 to 7,766 MW and 3,606 MW in the first six months of 2020.

Table 3-19 Average hourly number of cleared and submitted INCs and DECs by month: January 2019 through June 2020

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	2,934	6,777	282	1,122	3,856	7,149	215	834
2019	Feb	2,895	5,776	260	1,029	3,441	6,115	197	781
2019	Mar	2,973	5,961	268	1,057	3,319	6,830	181	859
2019	Apr	3,048	6,008	286	1,060	3,104	6,226	154	733
2019	May	3,107	6,468	273	1,082	4,236	6,903	178	726
2019	Jun	2,892	6,363	226	977	4,408	7,245	226	863
2019	Jul	2,655	6,712	202	1,051	4,544	9,223	251	1,086
2019	Aug	2,577	6,573	220	1,100	3,744	7,056	217	860
2019	Sep	2,715	6,737	221	972	5,046	8,790	255	900
2019	Oct	3,034	6,967	283	1,141	3,218	7,226	186	776
2019	Nov	3,373	7,896	304	1,261	2,745	6,930	187	831
2019	Dec	2,482	6,398	232	995	2,782	6,455	191	694
2019	Annual	2,889	6,558	255	1,071	3,704	7,186	203	829
2020	Jan	2,684	6,395	261	1,063	2,547	5,856	187	662
2020	Feb	2,544	7,043	233	1,046	2,990	6,653	222	702
2020	Mar	2,435	7,119	258	1,069	3,203	7,688	251	762
2020	Apr	2,655	7,738	299	1,167	3,400	8,312	261	840
2020	May	2,695	6,931	254	1,050	4,361	8,257	307	814
2020	Jun	2,353	7,185	235	1,011	5,140	9,843	404	1,083
2020	Jan-Jun	2,562	7,064	257	1,068	3,606	7,766	272	810

Table 3-20 shows the average hourly number of up to congestion transactions and the average hourly MW from January 2019 through June 2020. In the first six months of 2020, the average hourly submitted and cleared up to congestion MW decreased by 32.8 percent and 5.8 percent, compared to the first six months of 2019.

Table 3-20 Average hourly cleared and submitted up to congestion bids by month: January 2019 through June 2020

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	20,624	65,533	1,219	2,489
2019	Feb	21,341	66,240	1,005	2,013
2019	Mar	23,205	75,760	1,045	2,144
2019	Apr	21,323	63,388	872	1,669
2019	May	19,407	59,684	862	1,713
2019	Jun	18,598	51,678	1,021	1,953
2019	Jul	19,197	56,161	1,128	2,265
2019	Aug	20,247	58,841	1,254	2,550
2019	Sep	20,005	74,494	1,136	2,523
2019	Oct	22,233	75,107	1,093	2,302
2019	Nov	23,678	77,890	1,019	2,265
2019	Dec	20,567	55,020	1,040	2,104
2019	Annual	20,864	64,952	1,059	2,168
2020	Jan	19,106	37,533	1,127	2,087
2020	Feb	19,415	40,281	1,100	2,133
2020	Mar	19,513	40,998	990	1,970
2020	Apr	18,267	37,298	955	1,859
2020	May	18,028	41,503	1,122	2,425
2020	Jun	23,038	59,520	1,403	2,726
2020	Jan-Jun	19,551	42,823	1,116	2,200

Table 3-21 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2019 through June 2020. In the first six months of 2020, the average hourly submitted and cleared import transaction MW decreased by 35.7 and 30.2 percent, and the average hourly submitted and cleared export transaction MW increased by 10.0 and 10.0 percent, compared to the first six months of 2019.

Table 3-21 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2019 through June 2020

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2019	Jan	545	653	7	9	3,569	3,593	22	22
2019	Feb	564	671	6	8	3,169	3,182	17	18
2019	Mar	387	449	5	7	2,675	2,686	15	15
2019	Apr	255	288	4	5	2,483	2,496	15	15
2019	May	279	298	3	4	2,426	2,458	15	15
2019	Jun	291	308	3	4	2,790	2,806	17	17
2019	Jul	283	311	4	5	3,075	3,106	15	15
2019	Aug	277	303	3	4	2,907	2,923	16	16
2019	Sep	162	177	3	3	3,163	3,193	17	17
2019	Oct	433	463	4	5	2,694	2,721	15	15
2019	Nov	540	563	5	6	2,205	2,214	12	12
2019	Dec	468	505	4	6	3,133	3,144	25	25
2019	Annual	373	414	4	6	2,857	2,876	17	17
2020	Jan	427	445	5	6	3,034	3,041	28	28
2020	Feb	324	346	4	5	2,737	2,742	29	29
2020	Mar	254	269	3	4	3,084	3,085	27	27
2020	Apr	173	188	2	3	3,057	3,062	25	25
2020	May	207	231	3	4	3,075	3,080	23	23
2020	Jun	159	152	2	2	3,782	3,798	31	31
2020	Jan-Jun	267	283	3	4	3,129	3,136	27	27

Table 3-22 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal from January 2019 through June 2020.

Table 3-22 Type of day-ahead marginal resources: January 2019 through June 2020

	2019						2020					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	13.4%	0.3%	59.1%	17.4%	9.9%	0.0%	27.7%	0.1%	44.7%	10.6%	16.9%	0.0%
Feb	11.7%	0.1%	60.0%	15.4%	12.8%	0.0%	20.7%	0.1%	48.5%	12.5%	18.2%	0.0%
Mar	9.3%	0.1%	60.5%	17.0%	13.1%	0.0%	19.5%	0.0%	52.2%	14.7%	13.6%	0.0%
Apr	8.3%	0.1%	64.9%	14.8%	11.9%	0.0%	18.2%	0.0%	49.3%	16.6%	15.9%	0.0%
May	9.9%	0.1%	53.1%	21.0%	15.9%	0.0%	16.6%	0.1%	55.2%	15.2%	13.0%	0.0%
Jun	10.5%	0.0%	49.0%	23.7%	16.8%	0.0%	14.1%	0.0%	60.8%	15.5%	9.6%	0.0%
Jul	9.1%	0.0%	51.5%	26.0%	13.4%	0.0%						
Aug	13.0%	0.1%	63.1%	14.1%	9.6%	0.0%						
Sep	14.0%	0.1%	60.5%	13.4%	12.0%	0.0%						
Oct	16.4%	0.1%	55.9%	13.8%	13.8%	0.0%						
Nov	16.2%	0.0%	57.9%	13.2%	12.8%	0.0%						
Dec	23.2%	0.1%	55.2%	10.9%	10.5%	0.0%						
Annual	12.7%	0.1%	57.4%	17.0%	12.8%	0.0%	19.2%	0.1%	52.3%	14.2%	14.3%	0.0%

Figure 3-23 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005 through June 2020.

Figure 3-23 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through June 2020

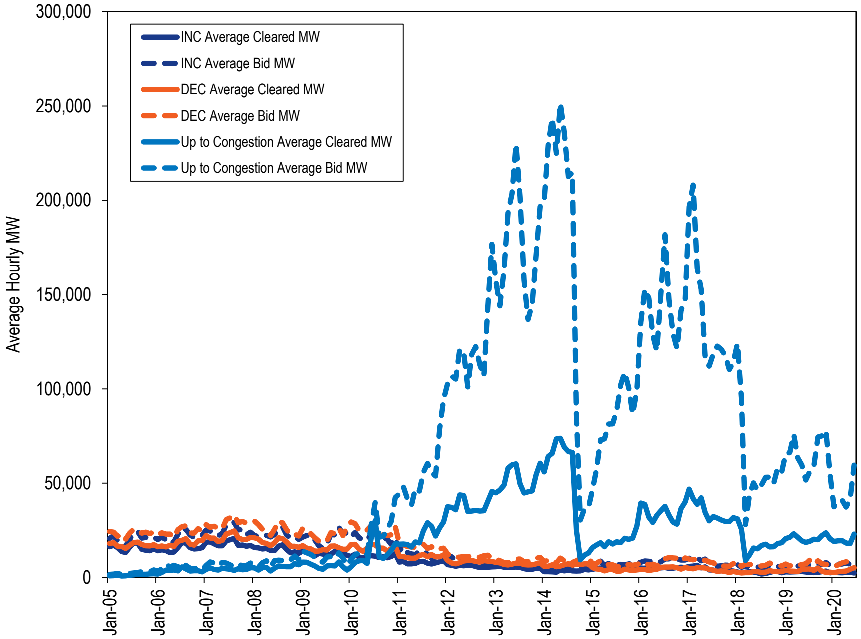
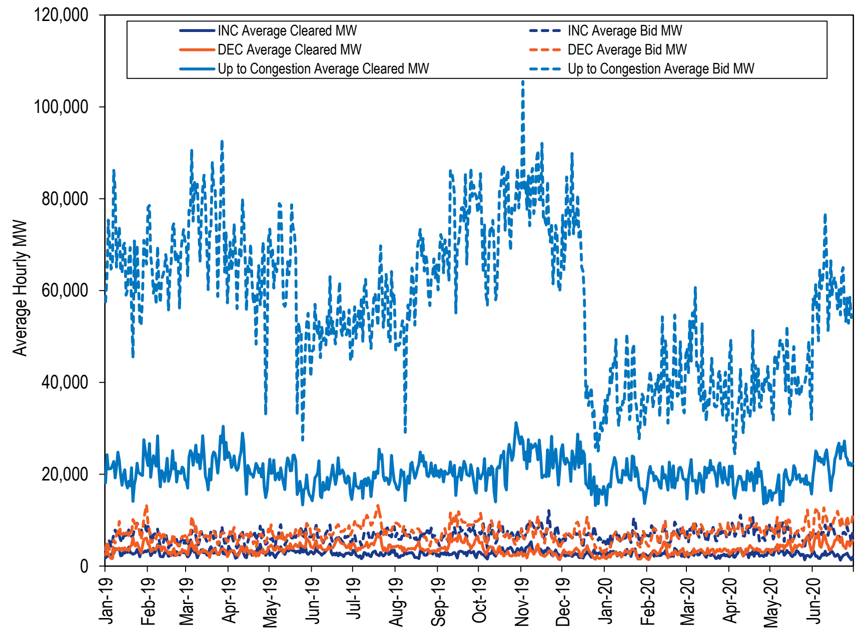


Figure 3-24 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2019 through June 30, 2020.

Figure 3-24 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2019 through June 2020



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-23 shows, in the first six months of 2019 and 2020, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-23 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through June, 2019 and 2020

	2019 (Jan-Jun)				2020 (Jan-Jun)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	48,814,769	86.5%	24,339,528	83.5%	56,011,511	86.6%	22,355,023	83.1%
Physical	7,595,601	13.5%	4,795,044	16.5%	8,701,301	13.4%	4,538,858	16.9%
Total	56,410,370	100.0%	29,134,571	100.0%	64,712,812	100.0%	26,893,881	100.0%

Table 3-24 shows, in the first six months of 2019 and 2020, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-24 Up to congestion transactions by type of parent organization (MWh): January through June, 2019 and 2020

	2019 (Jan-Jun)				2020 (Jan-Jun)			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	268,687,605	97.1%	84,856,254	94.2%	168,258,197	90.0%	76,196,501	89.2%
Physical	8,124,983	2.9%	5,252,250	5.8%	18,750,233	10.0%	9,181,987	10.8%
Total	276,812,587	100.0%	90,108,504	100.0%	187,008,431	100.0%	85,378,488	100.0%

Table 3-25 shows in the first six months of 2019 and 2020, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-25 Import and export transactions by type of parent organization (MW): January through June, 2019 and 2020

		2019 (Jan-Jun)		2020 (Jan-Jun)	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	3,668,084	26.1%	5,177,737	35.2%
	Physical	10,373,544	73.9%	9,547,594	64.8%
	Total	14,041,627	100.0%	14,725,330	100.0%
Real-Time	Financial	6,344,931	23.2%	7,716,943	29.9%
	Physical	21,011,743	76.8%	18,067,743	70.1%
	Total	27,356,674	100.0%	25,784,687	100.0%

Table 3-26 shows increment offers and decrement bids by top 10 locations in the first six months of 2019 and 2020.

Table 3-26 Virtual offers and bids by top 10 locations (MW): January through June, 2019 and 2020

2019 (Jan-Jun)					2020 (Jan-Jun)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
MISO	INTERFACE	74,384	3,216,498	3,290,882	MISO	INTERFACE	26,971	3,560,904	3,587,875
WESTERN HUB	HUB	670,231	728,727	1,398,958	WESTERN HUB	HUB	369,326	1,083,234	1,452,560
LINDENVFT	INTERFACE	16,411	852,801	869,212	AEP-DAYTON HUB	HUB	161,857	620,286	782,144
SOUTHIMP	INTERFACE	777,005	0	777,005	BGE_RESID_AGG	RESIDUAL METERED EDC	156,360	609,870	766,230
DOM_RESID_AGG	RESIDUAL METERED EDC	143,261	610,567	753,827	DOM_RESID_AGG	RESIDUAL METERED EDC	94,861	632,232	727,092
DOMINION HUB	HUB	371,321	370,699	742,020	PECO_RESID_AGG	RESIDUAL METERED EDC	389,685	99,669	489,354
AEP-DAYTON HUB	HUB	305,543	414,315	719,858	NORTHWEST	INTERFACE	364,381	105,376	469,758
N ILLINOIS HUB	HUB	281,063	306,988	588,051	N ILLINOIS HUB	HUB	171,493	260,760	432,253
NYIS	INTERFACE	415,153	158,993	574,146	NYIS	INTERFACE	394,017	31,665	425,682
NEW JERSEY HUB	HUB	388,117	118,779	506,896	PPL_RESID_AGG	RESIDUAL METERED EDC	330,291	75,809	406,100
Top ten total		3,442,489	6,778,366	10,220,856			2,459,242	7,079,805	9,539,047
PJM total		12,926,938	16,207,634	29,134,571			11,188,379	15,748,543	26,936,922
Top ten total as percent of PJM total		26.6%	41.8%	35.1%			22.0%	45.0%	35.4%

Table 3-27 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first six months of 2019 and 2020.[34]

Table 3-27 Cleared up to congestion import bids by top 10 source and sink pairs (MW): January through June, 2019 and 2020

2019 (Jan-Jun)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	2,738,366	$901,526	($287,823)	$613,703
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,758,049	$681,317	($354,864)	$326,453
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,615,387	$795,234	($378,123)	$417,111
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	981,191	($408,170)	$567,343	$159,173
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	735,826	$1,248,270	($769,591)	$478,680
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	717,623	$200,055	($135,340)	$64,715
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	690,960	$372,014	($340,012)	$32,002
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	661,045	$201,153	$51,623	$252,776
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	592,731	$396,471	($42,542)	$353,929
SOUTHIMP	INTERFACE	DOMINION HUB	HUB	429,275	$445,042	($406,103)	$38,938
Top ten total				10,920,454	$4,832,915	($2,095,434)	$2,737,481
PJM total				20,537,987	$11,876,242	($6,540,593)	$5,335,649
Top ten total as percent of PJM total				53.2%	40.7%	32.0%	51.3%
2020 (Jan-Jun)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	2,520,539	$2,127,741	($1,137,955)	$989,785
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,231,016	$1,459,200	($191,668)	$1,267,532
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,389,204	$1,246,554	($870,092)	$376,461
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	791,211	($240,958)	$284,793	$43,835
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	743,284	($603,348)	$362,548	($240,800)
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	544,053	$140,735	($51,817)	$88,918
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	469,927	($72,926)	$113,628	$40,702
NORTHWEST	INTERFACE	AEP-DAYTON HUB	HUB	450,885	$572,408	($175,882)	$396,526
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	435,637	$394,685	($224,096)	$170,589
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	335,218	$217,670	$55,841	$273,511
Top ten total				9,910,974	$5,241,760	($1,834,701)	$3,407,060
PJM total				16,364,450	$6,429,559	($1,297,464)	$5,132,095
Top ten total as percent of PJM total				60.6%	81.5%	141.4%	66.4%

34 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-28 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first six months of 2019 and 2020.

Table 3-28 Cleared up to congestion export bids by top 10 source and sink pairs (MW): January through June, 2019 and 2020

2019 (Jan-Jun)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	1,073,902	$1,447,949	($943,687)	$504,262
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	951,722	$1,172,116	($491,872)	$680,244
CHICAGO HUB	HUB	NIPSCO	INTERFACE	847,905	$1,195,494	$133,543	$1,329,037
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	796,735	$577,220	($45,838)	$531,382
CHICAGO HUB	HUB	MISO	INTERFACE	546,666	$321,666	($256,635)	$65,030
N ILLINOIS HUB	HUB	MISO	INTERFACE	393,987	$96,059	($138,381)	($42,322)
CHICAGO GEN HUB	HUB	MISO	INTERFACE	372,498	$129,807	($84,760)	$45,047
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	355,882	$238,525	$108,388	$346,913
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	335,566	($401,916)	$465,062	$63,146
AEP GEN HUB	HUB	NIPSCO	INTERFACE	216,228	($717,055)	$823,418	$106,363
Top ten total				5,891,090	$4,059,864	($430,762)	$3,629,101
PJM total				10,063,219	$4,867,436	$694,467	$5,561,903
Top ten total as percent of PJM total				58.5%	83.4%	(62.0%)	65.2%
2020 (Jan-Jun)							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,565,759	$1,394,315	($951,202)	$443,113
COMED_RESID_AGG	AGGREGATE	MISO	INTERFACE	874,105	$11,939	$235,372	$247,310
CHICAGO HUB	HUB	NIPSCO	INTERFACE	709,858	$303,801	($170,272)	$133,529
COMED_RESID_AGG	AGGREGATE	NORTHWEST	INTERFACE	642,793	($925,125)	$1,436,355	$511,230
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	549,227	$204,334	($54,058)	$150,276
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	409,116	$318,507	($296,361)	$22,146
CHICAGO HUB	HUB	MISO	INTERFACE	329,963	($237,847)	$293,841	$55,994
CHICAGO GEN HUB	HUB	MISO	INTERFACE	286,823	$3,879	($17,336)	($13,457)
COMED_RESID_AGG	AGGREGATE	SOUTHEXP	INTERFACE	247,401	($38,443)	$191,656	$153,213
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	175,439	$57,602	$34,825	$92,427
Top ten total				5,790,483	$1,092,960	$702,820	$1,795,781
PJM total				8,519,048	($45,239)	$2,161,039	$2,115,800
Top ten total as percent of PJM total				68.0%	(2416.0%)	32.5%	84.9%

Table 3-29 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first six months of 2019 and 2020.

Table 3-29 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January through June, 2019 and 2020

2019 (Jan-Jun)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	1,123,672	$987,100	($402,029)	$585,070
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	1,031,505	$862,401	($350,040)	$512,361
NORTHWEST	INTERFACE	MISO	INTERFACE	677,564	$654,921	($415,352)	$239,569
MISO	INTERFACE	NORTHWEST	INTERFACE	441,855	$4,320	$242,083	$246,403
SOUTHIMP	INTERFACE	MISO	INTERFACE	312,890	$223,114	($15,575)	$207,538
MISO	INTERFACE	SOUTHEXP	INTERFACE	282,257	$55,190	$1,014,930	$1,070,120
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	267,332	$307,020	$475,509	$782,529
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	134,512	($2,973)	$50,625	$47,652
NYIS	INTERFACE	IMO	INTERFACE	76,366	($44,381)	$46,846	$2,465
IMO	INTERFACE	SOUTHEXP	INTERFACE	55,554	$59,353	$98,153	$157,506
Top ten total				4,403,508	$3,106,065	$745,149	$3,851,214
PJM total				5,171,240	$3,414,863	$382,252	$3,797,115
Top ten total as percent of PJM total				85.2%	91.0%	194.9%	101.4%
2020 (Jan-Jun)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	1,244,193	$1,121,893	($440,648)	$681,245
MISO	INTERFACE	NIPSCO	INTERFACE	746,976	$230,632	($156,299)	$74,333
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	674,341	$339,914	($111,066)	$228,849
SOUTHIMP	INTERFACE	MISO	INTERFACE	515,216	($295,360)	$195,002	($100,359)
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	316,133	($42,281)	$61,116	$18,835
MISO	INTERFACE	SOUTHEXP	INTERFACE	291,194	$88,796	$2,856	$91,652
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	191,238	($40,005)	($31,777)	($71,782)
MISO	INTERFACE	NORTHWEST	INTERFACE	92,729	$49,503	$5,607	$55,109
NEPTUNE	INTERFACE	HUDSONTP	INTERFACE	47,267	($7,751)	($15,234)	($22,985)
SOUTHIMP	INTERFACE	NORTHWEST	INTERFACE	42,871	$27,319	$16,014	$43,333
Top ten total				4,162,158	$1,472,661	($474,430)	$998,231
PJM total				4,542,415	$1,400,555	($387,739)	$1,012,817
Top ten total as percent of PJM total				91.6%	105.1%	122.4%	98.6%

The top 10 internal up to congestion transaction locations were 23.3 percent of the PJM total internal up to congestion transactions MW in the first six months of 2020.

Table 3-30 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first six months of 2019 and 2020. The total internal UTC profits increased by $6.0 million, from -$0.9 million in the first six months of 2019 to $5.1 million in the first six months of 2020. The total internal cleared MW increased by 1.6 million MW, or 3.0 percent, from 54.3 million MW in the first six months of 2019 to 56.0 million MW in the first six months of 2020.

Table 3-30 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): January through June, 2019 and 2020

2019 (Jan-Jun)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,446,145	$619,897	($861,884)	($241,988)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,105,106	$1,216,373	($846,207)	$370,166
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,018,437	$485,933	($353,899)	$132,034
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,014,721	$494,126	($463,534)	$30,592
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	883,731	$598,554	($797,514)	($198,960)
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	797,331	$711,868	($714,031)	($2,163)
AEP GEN HUB	HUB	ATSI GEN HUB	HUB	636,785	$226,884	($415,550)	($188,667)
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	594,612	($298,038)	($5,854)	($303,892)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	570,382	$216,789	($132,373)	$84,416
OVEC_RESID_AGG	AGGREGATE	OHIO HUB	HUB	549,435	$324,534	($352,921)	($28,387)
Top ten total				8,616,684	$4,596,921	($4,943,768)	($346,847)
PJM total				54,336,058	$26,143,237	($26,998,983)	($855,747)
Top ten total as percent of PJM total				15.9%	17.6%	18.3%	40.5%
2020 (Jan-Jun)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	2,269,083	($61,990)	$292,072	$230,082
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,213,226	$223,583	($163,412)	$60,170
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,328,174	$248,162	$70,501	$318,663
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,262,526	$63,265	$367,843	$431,108
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,195,478	($5,065)	($75,227)	($80,292)
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,175,737	$178,654	($255,665)	($77,011)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	994,930	$150,833	$142,922	$293,755
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	921,425	$40,369	$250,328	$290,697
AEP GEN HUB	HUB	DAY_RESID_AGG	AGGREGATE	914,239	$138,073	($123,890)	$14,182
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	776,081	($4,929)	$41,447	$36,518
Top ten total				13,050,898	$970,955	$546,918	$1,517,873
PJM total				55,952,575	($2,101,288)	$7,220,285	$5,118,997
Top ten total as percent of PJM total				23.3%	(46.2%)	7.6%	29.7%

Table 3-31 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2019 through June 30, 2020.

Table 3-31 Number of offered and cleared source and sink pairs: January 2019 through June 2020

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2019	Jan	1,693	1,893	1,527	1,712
2019	Feb	1,701	1,881	1,496	1,733
2019	Mar	1,673	1,806	1,506	1,653
2019	Apr	1,555	1,806	1,395	1,653
2019	May	1,584	1,856	1,424	1,718
2019	Jun	1,770	1,970	1,601	1,797
2019	Jul	1,767	1,950	1,635	1,819
2019	Aug	1,880	2,034	1,690	1,879
2019	Sep	1,891	2,007	1,702	1,842
2019	Oct	1,837	1,935	1,607	1,756
2019	Nov	1,796	1,984	1,576	1,700
2019	Dec	1,687	1,935	1,507	1,769
2019	Annual	1,736	1,921	1,555	1,753
2020	Jan	1,658	1,942	1,523	1,857
2020	Feb	1,710	1,975	1,568	1,725
2020	Mar	1,789	2,013	1,591	1,832
2020	Apr	1,804	1,978	1,567	1,760
2020	May	1,913	2,126	1,681	1,900
2020	Jun	1,974	2,111	1,803	2,020
2020	Jan-Jun	1,719	1,977	1,561	1,805

Table 3-32 and Figure 3-25 show total cleared up to congestion transactions by type in the first six months of 2019 and 2020. Total up to congestion transactions in the first six months of 2020 decreased by 5.2 percent from 90.1 million MW in the first six months of 2019 to 85.4 million MW in the first six months of 2020. Internal up to congestion transactions in the first six months of 2020 were 65.5 percent of all up to congestion transactions compared to 60.3 percent in the first six months of 2019.

Table 3-32 Cleared up to congestion transactions by type (MW): January through June, 2019 and 2020

	2019 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,920,454	5,891,090	4,403,508	8,616,684	29,831,737
PJM total (MW)	20,537,987	10,063,219	5,171,240	54,336,058	90,108,503
Top ten total as percent of PJM total	53.2%	58.5%	85.2%	15.9%	33.1%
PJM total as percent of all up to congestion transactions	22.8%	11.2%	5.7%	60.3%	100.0%
	2020 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	9,910,974	5,790,483	4,162,158	13,050,898	32,914,514
PJM total (MW)	16,364,450	8,519,048	4,542,415	55,952,575	85,378,488
Top ten total as percent of PJM total	60.6%	68.0%	91.6%	23.3%	38.6%
PJM total as percent of all up to congestion transactions	19.2%	10.0%	5.3%	65.5%	100.0%

Figure 3-25 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[35] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. But in 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[36] The order limited UTC trading to hubs, residual metered load, and interfaces. The reduction in UTC bid locations effective February 22, 2018, resulted in a significant reduction in total activity. UTC activity has increased, following that reduction.

35 See 162 FERC ¶ 61,139 (2018).
36 *Id.*

Figure 3-25 Monthly cleared up to congestion transactions by type (MW): January 2005 through June 2020

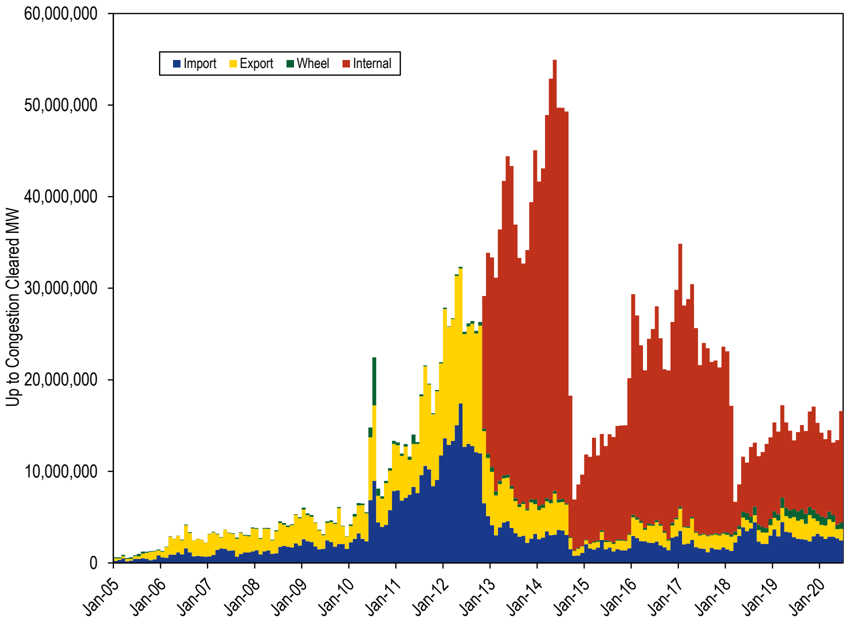
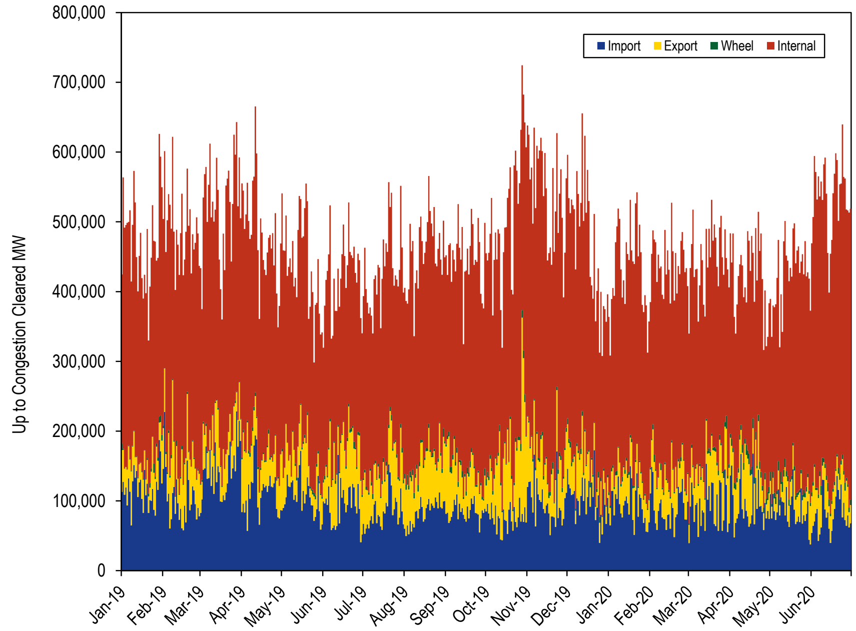


Figure 3-26 shows the daily cleared up to congestion MW by transaction type from January 1, 2019 through June 30, 2020.

Figure 3-26 Daily cleared up to congestion transaction by type (MW): January 2019 through June 2020



Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 29.4 percent and 31.3 percent lower in the first six months of 2020 than in the first six months of 2019. As a combined result of weather, COVID-19 related demand reductions, low loads and low gas prices, energy prices were lower in the first six months of 2020 than in any comparable period since the beginning of PJM markets on April 1, 1999.

PJM real-time energy market prices decreased in the first six months of 2020 compared to the first six months of 2019. The average LMP was 29.2 percent lower in the first six months of 2020 than in the first six months of 2019, $18.70 per MWh versus $26.41 per MWh. The load-weighted average real-time LMP was 29.4 percent lower in the first six months of 2020 than in the first six months of 2019, $19.40 per MWh versus $27.49 per MWh.

The real-time load-weighted average LMP for the first six months of 2020 was 17.6 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2020. If fuel and emission costs in the first six months of 2020 had been the same as in the first six months of 2019, holding everything else constant, the load-weighted LMP would have been higher, $23.55 per MWh instead of the observed $19.40 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2020 compared to the first six months of 2019. The day-ahead average LMP was 30.9 percent lower in the first six months of 2020 than in the first six months of 2019, $18.55 per MWh versus $26.86 per MWh. The day-ahead load-weighted average LMP was 31.3 percent lower in the first six months of 2020 than in the first six months of 2019, $19.23 per MWh versus $27.97 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[37] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[38]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price

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

38 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[39]

PJM Real-Time, Average LMP

Table 3-33 shows the PJM real-time, average LMP for the first six months of 1998 through 2020.[40]

Table 3-33 Real-time, average LMP (Dollars per MWh): January through June, 1998 through 2020

	Real-Time LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)
2016	$25.84	$23.17	$13.61	(33.5%)	(20.2%)	(60.0%)
2017	$28.72	$25.76	$12.03	11.1%	11.2%	(11.6%)
2018	$38.82	$27.21	$38.76	35.2%	5.6%	222.3%
2019	$26.41	$23.81	$15.75	(32.0%)	(12.5%)	(59.4%)
2020	$18.70	$17.54	$8.46	(29.2%)	(26.3%)	(46.3%)

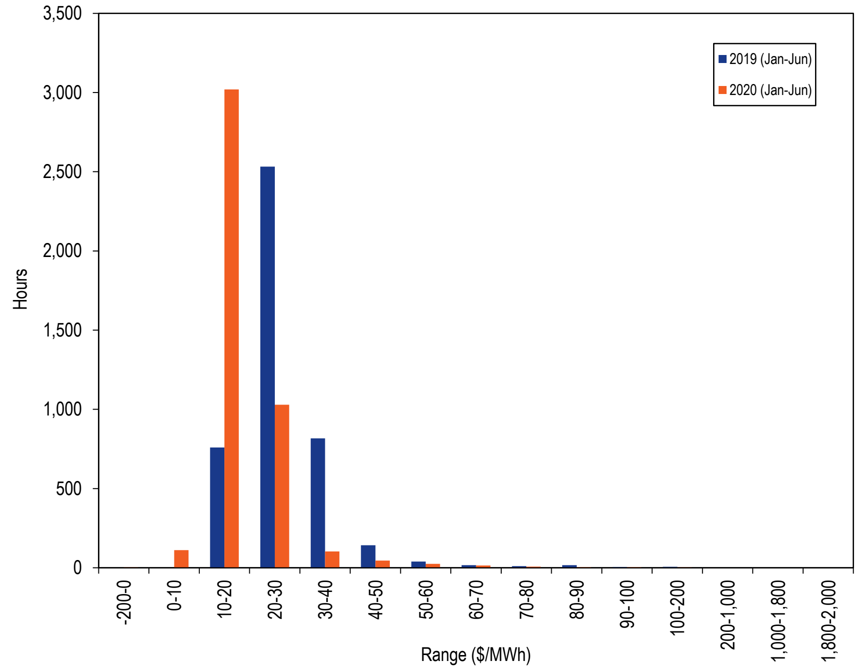
39 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

40 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time Average LMP Duration

Figure 3-27 shows the hourly distribution of PJM real-time average LMP for the first six months of 2019 and 2020.

Figure 3-27 Average LMP for the Real-Time Energy Market: January through June, 2019 and 2020



Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-34 shows the PJM real-time, load-weighted, average LMP for the first six months of 1998 through 2020.

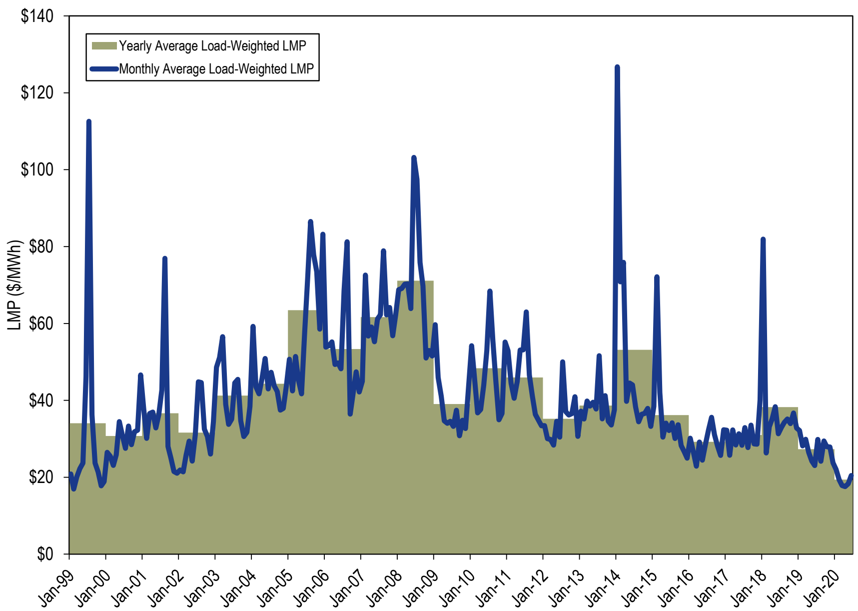
Table 3-34 Real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2020

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)
2016	$27.09	$23.82	$14.49	(36.0%)	(21.5%)	(61.7%)
2017	$29.81	$26.47	$12.88	10.1%	11.1%	(11.1%)
2018	$42.44	$28.36	$43.68	42.4%	7.1%	239.1%
2019	$27.49	$24.40	$16.38	(35.2%)	(14.0%)	(62.5%)
2020	$19.40	$18.13	$8.93	(29.4%)	(25.7%)	(45.5%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-28 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through June 2020.

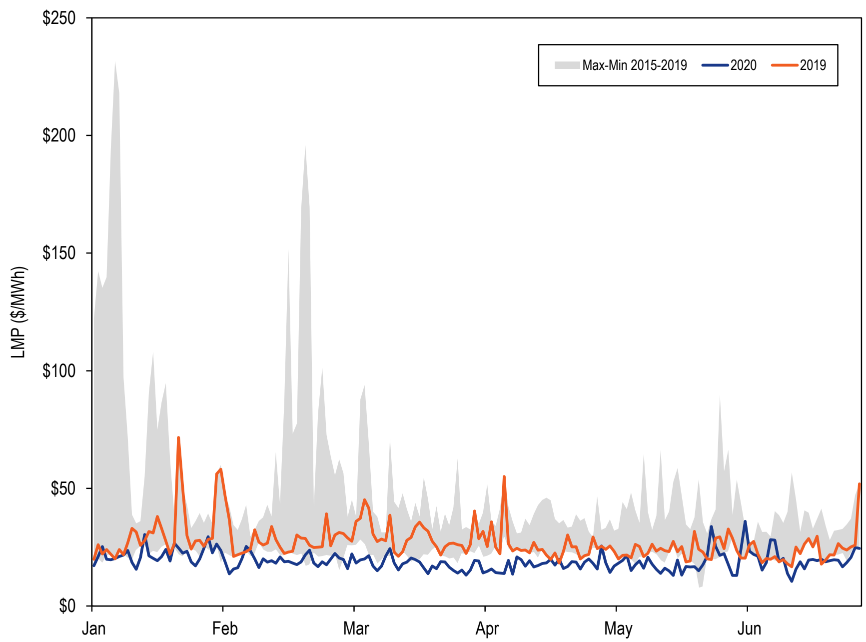
Figure 3-28 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through June 2020



PJM Real-Time, Daily, Load-Weighted, Average LMP

Figure 3-29 shows the PJM real-time daily load-weighted LMP for the first six months of 2019 and 2020.

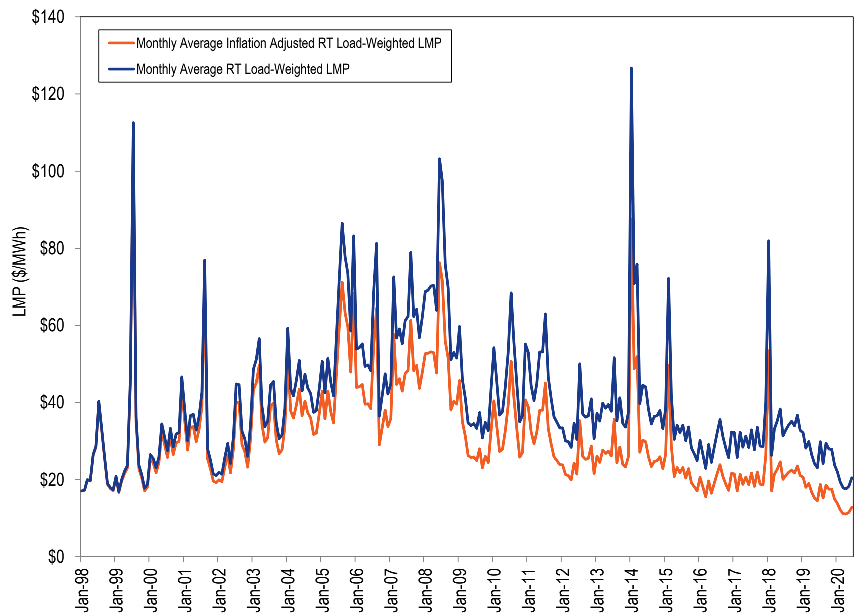
Figure 3-29 Real-time, daily, load-weighted, average LMP: January through June, 2019 and 2020



PJM Real-Time, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-30 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through June 2020.[41] Table 3-35 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for the first six months of every year from 1998 through 2020. The PJM real-time inflation adjusted load-weighted average LMP for the first six months of 2020 was the lowest value since PJM real-time markets started on April 1, 1999 at $12.17 per MWh. The real-time inflation adjusted monthly load-weighted average LMP for April 2020 was the lowest monthly value since PJM markets started in April 1999 at $11.08 per MWh.

Figure 3-30 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: January 1998 through June 2020



41 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed July 11, 2020)

Table 3-35 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: January through June, 1998 through 2020

	Load-Weighted, Average LMP (Jan-Jun)	Inflation Adjusted Load-Weighted, Average LMP (Jan-Jun)
1998	$21.66	$21.54
1999	$25.34	$24.74
2000	$27.76	$26.25
2001	$35.27	$32.27
2002	$25.93	$23.40
2003	$44.43	$39.18
2004	$47.62	$41.02
2005	$48.67	$40.71
2006	$51.83	$41.78
2007	$58.32	$45.83
2008	$74.77	$56.29
2009	$42.48	$32.26
2010	$45.75	$33.99
2011	$48.47	$35.04
2012	$31.21	$22.05
2013	$37.96	$26.40
2014	$69.92	$47.96
2015	$42.30	$28.98
2016	$27.09	$18.34
2017	$29.81	$19.74
2018	$42.44	$27.48
2019	$27.49	$17.48
2020	$19.40	$12.17

Real-Time Dispatch and Pricing

The PJM Real-Time Energy Market consists of a series 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).[42] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

The dispatch of reserves in LPC determines whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around the processes used to determine load bias in RT SCED, to approve RT SCED cases, and the use of RT SCED cases by LPC.

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. On average, PJM operators approve more than one RT SCED case per five minute interval to send dispatch signals to resources. PJM uses only a subset of these approved RT SCED cases in LPC to calculate real-time LMPs. As a result, a number of dispatch directives are not reflected in real-time energy market prices. Generally, LPC uses the latest available approved RT SCED case to calculate prices, regardless of the target dispatch time of the RT SCED case. However, LPC assigns the prices to a five minute interval that does not contain the target time of the RT SCED case it used.

Table 3-36 shows, on a monthly basis for the first six months of 2020, the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. PJM retains the discretion to change the automatic RT SCED execution frequency at any time, as the frequency is not documented in the PJM Market Rules. Each execution of RT SCED produces three solutions, using three different levels of load bias. Since prices are calculated every five minutes while three SCED solutions are produced every three to five minutes, there is, by definition, a larger number of solved SCED case solutions than there are five minute intervals in any given period. PJM operators approve a subset of RT SCED solutions to send dispatch signals to resources at an irregular frequency. This lack of a direct and regular connection between the dispatch signal and the price signal weakens the incentives to follow dispatch by generators, especially when RT SCED solutions that reflect shortage pricing are not used in calculating real-time prices in LPC.

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 108 (Dec. 3, 2019)

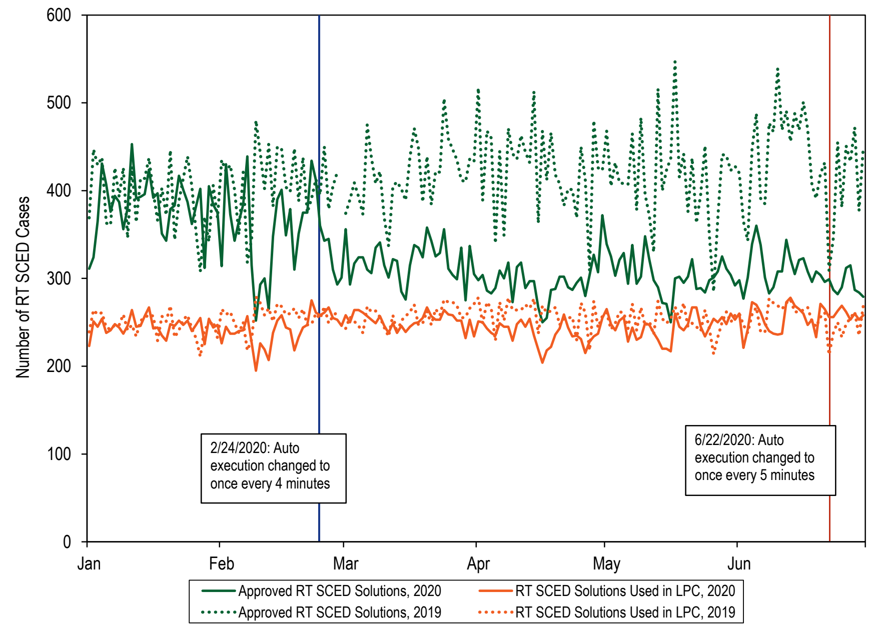
Table 3-36 shows that in the first six months of 2020 only 75.4 percent of approved RT SCED case solutions that are used to send dispatch signals to generators are used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased from 69.0 percent to 78.7 percent from February to March and further increased to 83.6 percent in June with the decrease in the frequency of executed RT SCED cases.

Figure 3-31 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in the first six months of 2019 and 2020, and the dates when the frequency of RT SCED auto execution was changed. Figure 3-31 shows that changing the auto execution frequency of RT SCED from once every three minutes to once every four minutes on February 24 reduced the number of approved RT SCED cases used to send dispatch signals in 2020 compared to 2019. This change in the frequency of approved solutions reduced the difference between the number of approved solutions and the number of solutions used in pricing in 2020 relative to 2019.

Table 3-36 RT SCED cases solved, approved and used in pricing: January through June, 2020

Month (2020)	Number of RT SCED Case Solutions	Number of Approved RT SCED Case Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	51,022	11,860	7,612	64.2%
Feb	46,247	10,149	7,005	69.0%
Mar	38,680	9,914	7,799	78.7%
Apr	36,543	8,888	7,132	80.2%
May	36,648	9,416	7,590	80.6%
Jun	34,327	9,165	7,666	83.6%
Total	243,467	59,392	44,804	75.4%

Figure 3-31 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: January through June, 2019 and 2020



PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs has inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. PJM does not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in the first six months of 2020, and cases are approved irregularly, while settlements are linked to five minute intervals. RT SCED solves the dispatch problem for a target time that is generally 10 to 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target do not match, and a new RT SCED case overrides the previously approved case before resources have time to achieve the previous target dispatch. The interval that is priced in LPC is consistently before the target time from the RT SCED case used for the dispatch signal. LPC takes the most recently approved RT SCED case to calculate LMPs. For example, the LPC case that calculates prices for the interval beginning 10:00 EPT uses an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy creates a mismatch between the MW dispatch and real-time LMPs and undermines generators' incentive to follow dispatch. Under RT SCED changes pending FERC approval, PJM will resolve the mismatch between LPC and the RT SCED target time, but prices will no longer apply at the time when resources receive and follow that dispatch signal.[43] The timing will remain incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all correspond to one another.

Table 3-37 compares the RT SCED target time and LPC interval beginning times for the first six months of 2020. LPC interval beginning time is the beginning time of the five minute interval for which LPC calculates LMPs. Table 3-37 shows that in the first six months of 2020, 60.7 percent of the five minute intervals have prices assigned for an interval that began 10 minutes prior to the dispatch target time and 34.8 percent of five minute intervals have prices assigned for a target interval that began five minutes prior to the dispatch target time.

Table 3-37 Difference in RT SCED target time and LPC interval beginning time: January through June, 2020

Difference between RT SCED target time and LPC interval beginning time (mins)	Percent of Five Minute Intervals
(10)	0.1%
(5)	0.4%
0	4.0%
5	34.8%
10	60.7%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.[44] The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved SCED case. This will result in prices used to settle energy for the five minute interval that ends at the SCED dispatch target time.

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 17:00 of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 17:00 of the second business day following the operating day.[45] Table 3-38 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2019 and 2020. In the first six months of 2020, PJM recalculated LMPs for 466 five minute intervals or 0.89 percent of the total 52,404 five minute intervals in the first six months.

43 See Docket No. ER19-2573-000.

44 See *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

45 OA Schedule 1 § 1.10.8(e).

Table 3-38 Number of five minute interval real-time prices recalculated: January, 2019 through June, 2020

	2019		2020	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	10	8,928	193
February	8,064	14	8,352	12
March	8,916	51	8,916	110
April	8,640	19	8,640	50
May	8,928	19	8,928	37
June	8,640	28	8,640	64
July	8,928	69		
August	8,928	79		
September	8,640	45		
October	8,928	115		
November	8,652	74		
December	8,928	11		
Total	105,120	534	52,404	466

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[46]

PJM Day-Ahead, Average LMP

Table 3-39 shows the PJM day-ahead, average LMP in the first six months of 2000 through 2020.

Table 3-39 Day-ahead, average LMP (Dollars per MWh): January through June, 2000 through 2020

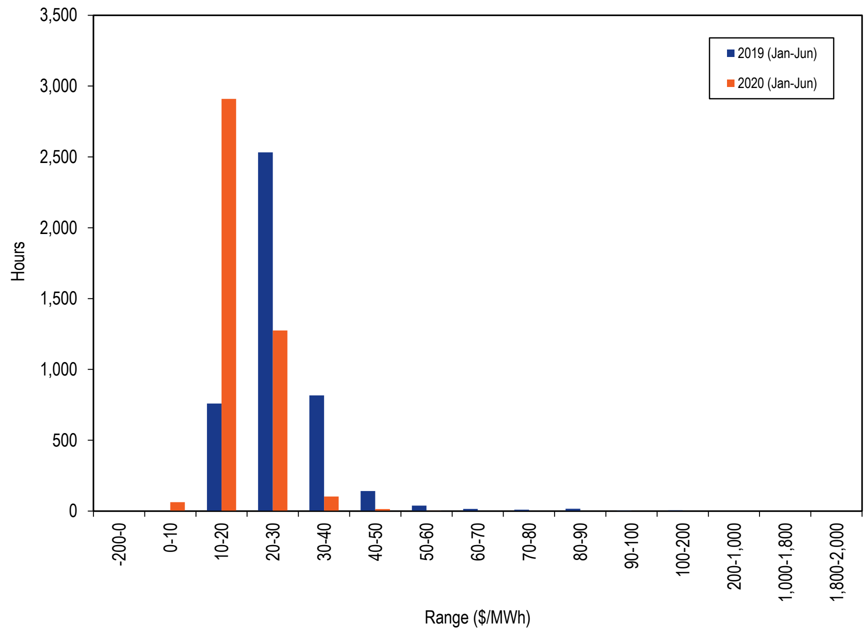
	Day-Ahead LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.29	$22.72	$19.75	NA	NA	NA
2001	$35.02	$31.34	$17.43	15.6%	38.0%	(11.8%)
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)
2016	$26.24	$24.95	$8.54	(34.4%)	(21.9%)	(70.3%)
2017	$29.03	$27.26	$8.87	10.6%	9.3%	3.9%
2018	$37.90	$30.08	$29.14	30.5%	10.3%	228.6%
2019	$26.86	$25.31	$9.56	(29.1%)	(15.8%)	(67.2%)
2020	$18.55	$18.20	$4.92	(30.9%)	(28.1%)	(48.6%)

46 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of PJM day-ahead average LMP in the first six months of 2019 and 2020.

Figure 3-32 Average LMP for the Day-Ahead Energy Market: January through June, 2019 and 2020



Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-40 shows the PJM day-ahead, load-weighted, average LMP in the first six months of 2000 through 2020.

Table 3-40 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2000 through 2020

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.7%	82.7%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)
2016	$27.33	$25.92	$8.89	(36.8%)	(22.5%)	(72.4%)
2017	$30.02	$28.21	$9.38	9.8%	8.8%	5.6%
2018	$40.96	$31.44	$32.70	36.5%	11.4%	248.5%
2019	$27.97	$26.10	$10.59	(31.7%)	(17.0%)	(67.6%)
2020	$19.23	$18.73	$5.14	(31.3%)	(28.2%)	(51.4%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-33 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through June 30, 2020.[47]

Figure 3-33 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through June 2020

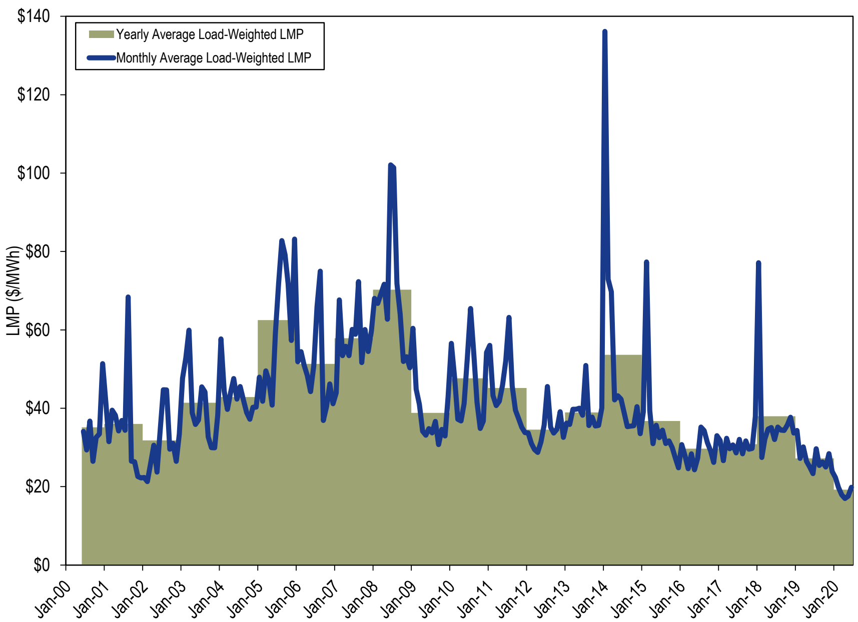
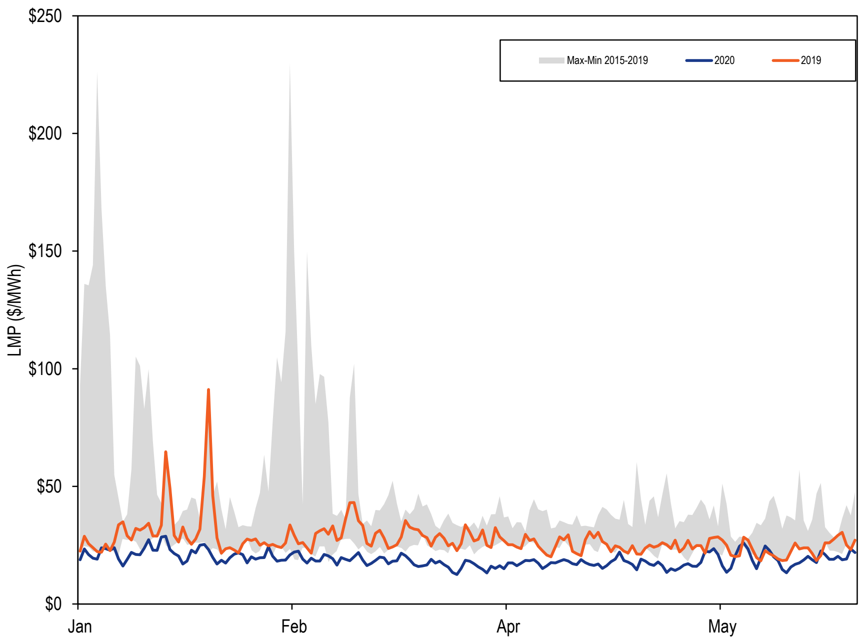


Figure 3-34 shows the PJM day-ahead daily load-weighted LMP for the first six months of 2019 and 2020.

Figure 3-34 Day-ahead, daily, load-weighted, average LMP: January through June, 2019 and 2020

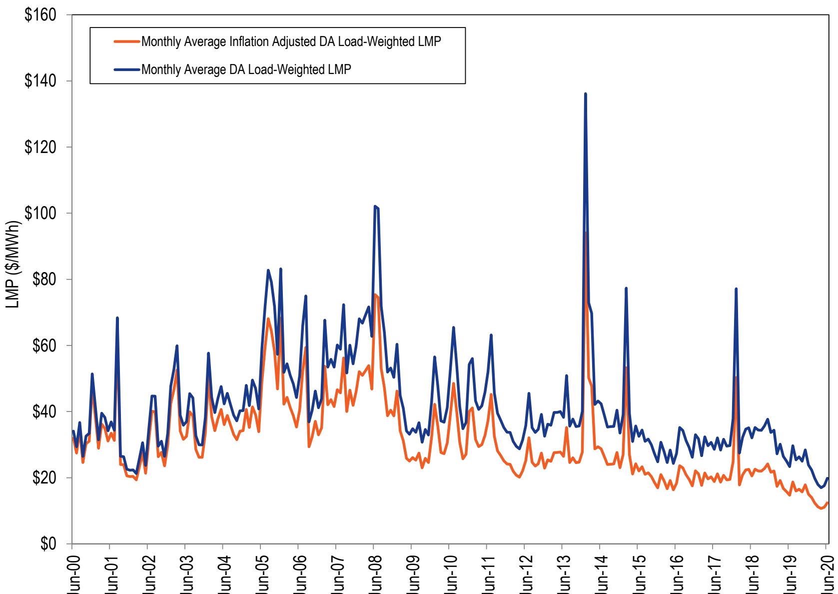


47 Since the day-ahead energy market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last seven months of that year.

PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-35 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through June 2020.[48] Table 3-41 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first six months of every year from 2001 through 2020. The PJM day-ahead inflation adjusted load-weighted average LMP for first six months of 2020 was the lowest first six month value ($12.06 per MWh) since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for April 2020 ($10.70 per MWh) was the lowest monthly value since the day-ahead markets started.

Figure 3-35 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through June 2020



48 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed July 11, 2020).

Table 3-41 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through June, 2001 through 2020

	Load-Weighted, Average LMP (Jan-Jun)	Inflation Adjusted Load-Weighted, Average LMP (Jan-Jun)
2000	$34.12	$31.98
2001	$37.08	$33.94
2002	$26.88	$24.25
2003	$45.62	$40.23
2004	$46.12	$39.73
2005	$48.12	$40.24
2006	$50.21	$40.47
2007	$55.70	$43.76
2008	$73.71	$55.49
2009	$42.21	$32.06
2010	$46.12	$34.28
2011	$47.12	$34.08
2012	$31.84	$22.49
2013	$38.23	$26.59
2014	$70.67	$48.48
2015	$43.26	$29.64
2016	$27.33	$18.51
2017	$30.02	$19.88
2018	$40.96	$26.52
2019	$27.97	$17.79
2020	$19.23	$12.06

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the day-ahead and real-time energy market.

Where arbitrage opportunities are created by differences between day-ahead and real-time energy market expectations, reactions by market participants may lead to more efficient market outcomes but there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from price differences between the day-ahead and real-time energy market. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-42 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first six months of 2019 and 2020. In the first six months of 2020, 52.1 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 62.1 percent were profitable on the source side and 38.3 were profitable on the sink side but only 7.3 percent were profitable on both the source and sink side.

Table 3-42 Cleared UTC profitability by source and sink point: January through June, 2019 and 2020[49]

(Jan-Jun)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	UTC Profitable at Source and Sink	Profitable UTC	Profitable Source	Profitable Sink	Profitable at Source and Sink
2019	4,363,096	2,060,568	2,991,574	1,368,737	253,756	47.2%	68.6%	31.4%	5.8%
2020	4,872,175	2,540,498	3,025,710	1,866,187	356,062	52.1%	62.1%	38.3%	7.3%

Table 3-43 shows the number of cleared INC and DEC transactions and the number of profitable cleared transactions in the first six months of 2019 and 2020. Of cleared INC and DEC transactions in the first six months of 2020, 64.0 percent of INCs were profitable and 40.0 percent of DECs were profitable.

Table 3-43 Cleared INC and DEC profitability: January through June, 2019 and 2020

(Jan-Jun)	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2019	1,155,107	799,296	69.2%	831,940	281,642	33.9%
2020	1,122,070	718,460	64.0%	1,187,461	475,213	40.0%

49 Calculations exclude PJM administrative charges.

Figure 3-36 shows total UTC daily gross profits, the sum of all positive profit UTC transactions, gross losses, the sum of all negative profit UTC transactions, and net profits and losses in the first six months of 2020.

Figure 3-36 UTC daily gross profits and losses and net profits: January through June, 2020[50]

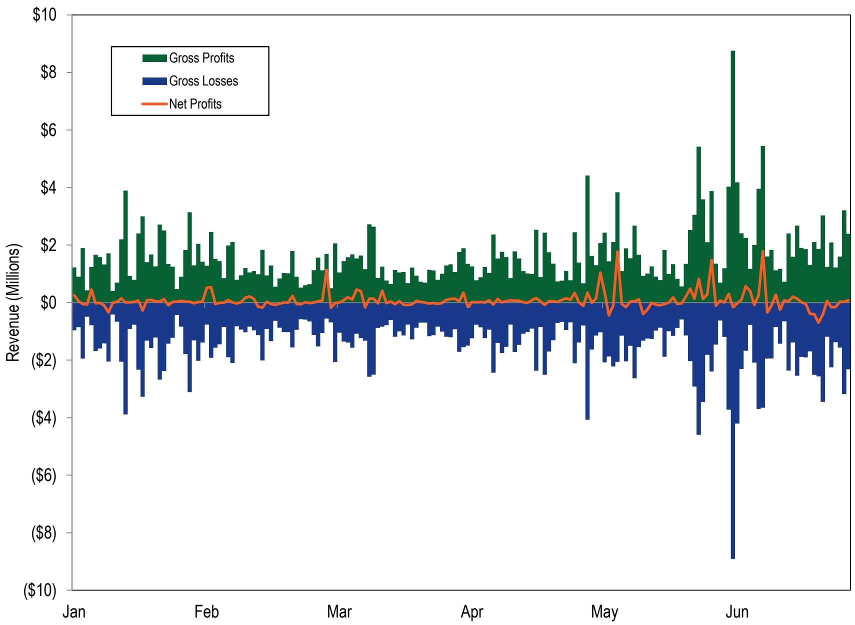
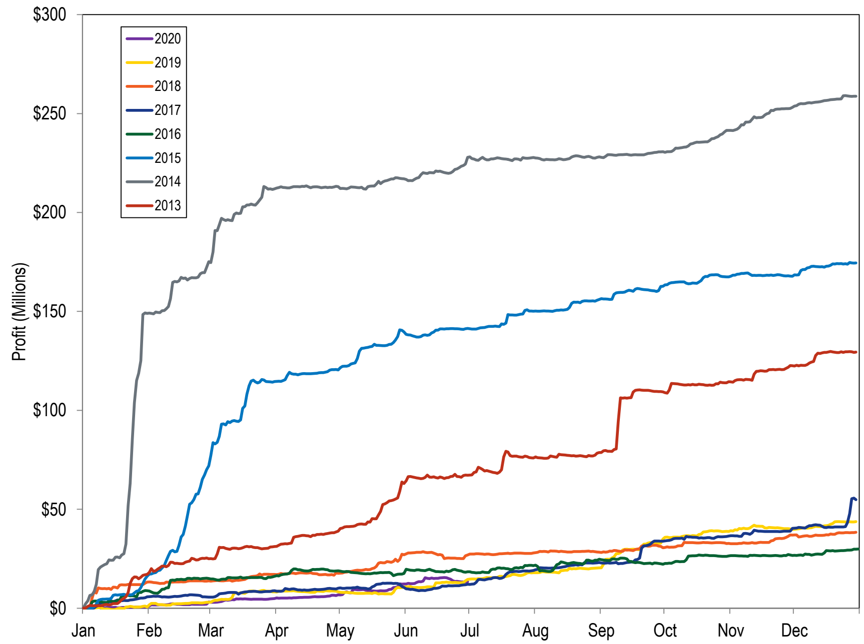


Figure 3-37 shows the cumulative UTC daily profits for each year from 2013 through June 2020.

Figure 3-37 Cumulative daily UTC profits: 2013 through June 2020



50 Calculations exclude PJM administrative charges.

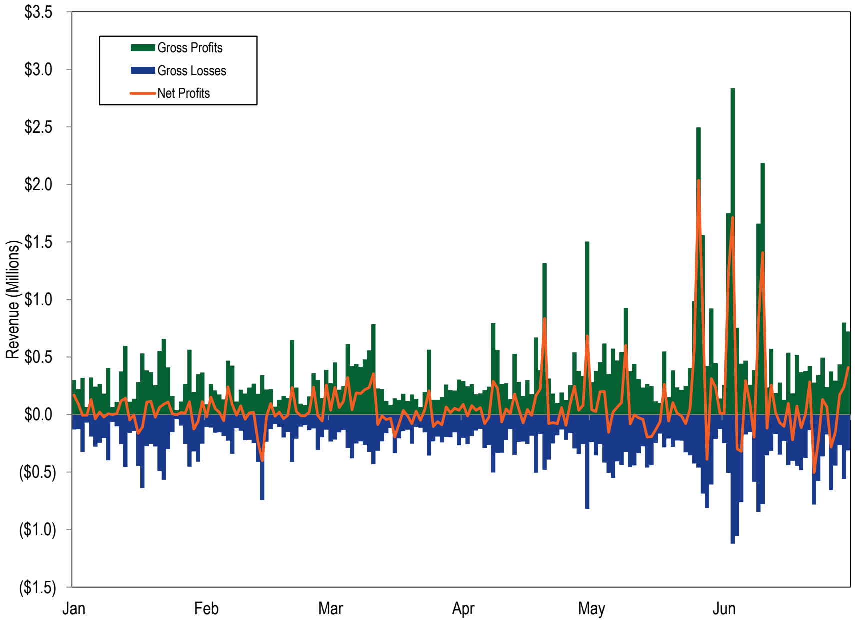
Table 3-44 shows UTC profits by month for 2013 through June 2020. May 2016, September 2016, February 2017 and June 2018 were the only months in this seven year period in which monthly profits were negative.

Table 3-44 UTC profits by month: January 2013 through June 2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429							$13,379,709

Figure 3-38 shows total INC and DEC daily gross profits, the sum of all positive profit transactions, gross losses, the sum of all negative profit transactions, and net profits and losses in the first six months of 2020.

Figure 3-38 INC and DEC daily gross profits and losses and net profits: January through June, 2020[51]



51 Calculations exclude PJM administrative charges.

Figure 3-39 shows total INC daily gross profits and losses and net profits and losses in the first six months of 2020.

Figure 3-39 INC daily gross profits and losses and net profits: January through June, 2020[52]

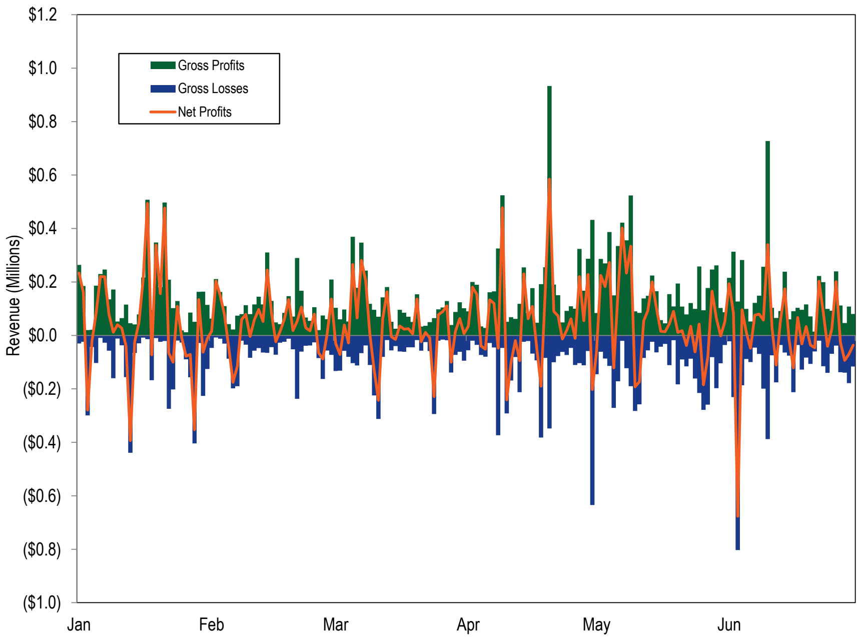
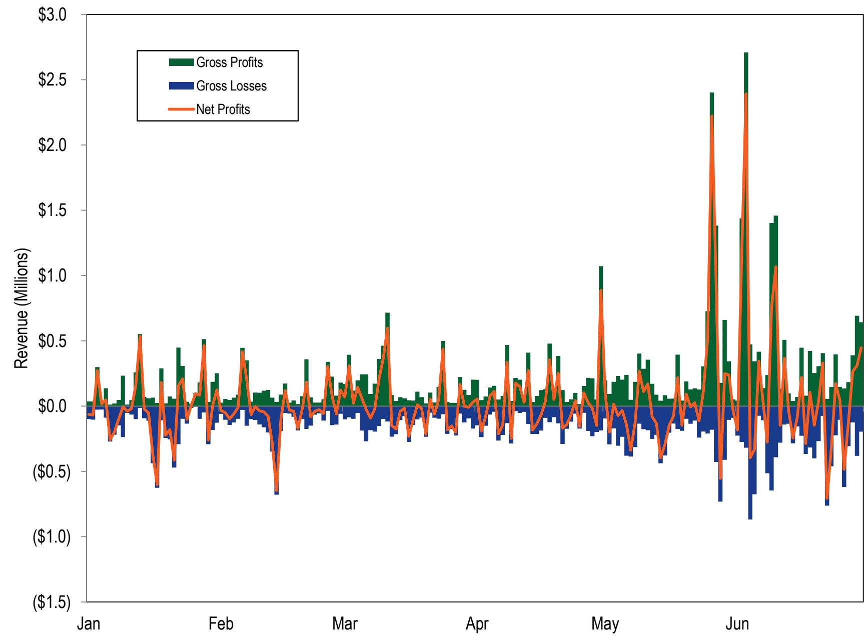


Figure 3-40 shows total DEC daily gross profits and losses and net profits and losses in the first six months of 2020.

Figure 3-40 DEC daily gross profits and losses and net profits: January through June, 2020[53]



52 Calculations exclude PJM administrative charges.

53 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits for January 1, through June 30, 2020.

Figure 3-41 Cumulative daily INC and DEC profits: January through June, 2020

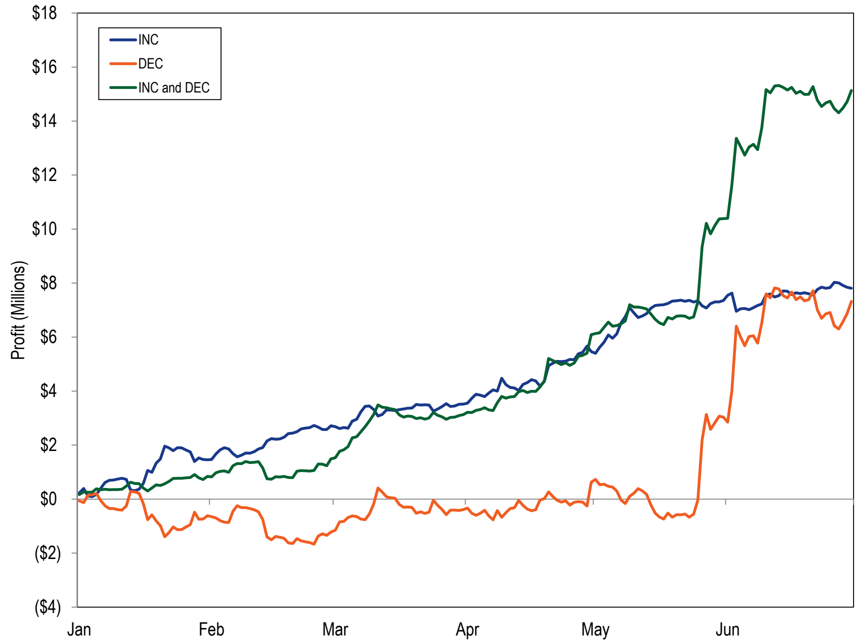


Table 3-45 shows INC and DEC profits by month for January through June 2020.

Table 3-45 INC and DEC profits by month: January through June, 2020

	January	February	March	April	May	June	Total
INCs	$1,455,089	$1,259,625	$803,233	$1,944,109	$1,893,382	$452,115	$7,807,553
DECs	($614,734)	($606,579)	$833,364	$1,017,052	$2,404,925	$4,289,805	$7,323,833
INCs and DECs	$840,356	$653,046	$1,636,597	$2,961,161	$4,298,306	$4,741,920	$15,131,386

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Table 3-46 shows that the difference between the average real-time price and the average day-ahead price was -$0.45 per MWh in the first six months of 2019 and $0.15 per MWh in the first six months of 2020. The difference between average peak real-time price and the average peak day-ahead price was -$0.76 per MWh in the first six months of 2019 and $0.30 per MWh in the first six months of 2020.

Table 3-46 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2019 and 2020[54]

	2019 (Jan-Jun)				2020 (Jan-Jun)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$26.86	$26.41	($0.45)	(1.7%)	$18.55	$18.70	$0.15	0.8%
Median	$25.31	$23.81	($1.51)	(6.3%)	$18.20	$17.54	($0.66)	(3.8%)
Standard deviation	$9.56	$15.75	$6.19	39.3%	$4.92	$8.46	$3.54	41.9%
Peak average	$30.61	$29.85	($0.76)	(2.6%)	$21.09	$21.38	$0.30	1.4%
Peak median	$28.15	$25.88	($2.27)	(8.8%)	$20.07	$19.35	($0.72)	(3.7%)
Peak standard deviation	$10.35	$19.44	$9.09	46.8%	$4.68	$10.05	$5.36	53.4%
Off peak average	$23.56	$23.39	($0.17)	(0.7%)	$16.32	$16.33	$0.02	0.1%
Off peak median	$22.46	$21.55	($0.91)	(4.2%)	$16.03	$15.74	($0.29)	(1.9%)
Off peak standard deviation	$7.37	$10.69	$3.32	31.0%	$3.93	$5.79	$1.86	32.1%

The price difference between the real-time and the day-ahead energy markets results in part, from conditions in the real-time energy market that are difficult, or impossible, to anticipate in the day-ahead energy market.

Table 3-47 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first six months of 2001 through 2020.

Table 3-47 Day-ahead load-weighted and real-time load-weighted average LMP (Dollars per MWh): January through June, 2001 through 2020

(Jan-Jun)	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)
2015	$39.98	$38.87	($1.11)	(2.8%)
2016	$26.24	$25.84	($0.40)	(1.5%)
2017	$29.03	$28.72	($0.31)	(1.1%)
2018	$37.90	$38.82	$0.93	2.4%
2019	$26.86	$26.41	($0.45)	(1.7%)
2020	$18.55	$18.70	$0.15	0.8%

54 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-48 includes frequency distributions of the differences between PJM real-time, load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first six months of 2019 and 2020.

Table 3-48 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through June, 2019 and 2020

	2019 (Jan-Jun)		2020 (Jan-Jun)	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%
($100) to ($50)	5	0.12%	0	0.00%
($50) to $0	3,022	69.70%	2,759	63.18%
$0 to $50	1,290	99.40%	1,598	99.77%
$50 to $100	15	99.75%	8	99.95%
$100 to $150	8	99.93%	1	99.98%
$150 to $200	1	99.95%	1	100.00%
$200 to $250	1	99.98%	0	100.00%
$250 to $300	0	99.98%	0	100.00%
$300 to $350	0	99.98%	0	100.00%
$350 to $400	0	99.98%	0	100.00%
$400 to $450	0	99.98%	0	100.00%
$450 to $500	0	99.98%	0	100.00%
$500 to $750	1	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%

Figure 3-42 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2020.

Figure 3-42 Real-time hourly LMP minus day-ahead hourly LMP: January through June, 2020

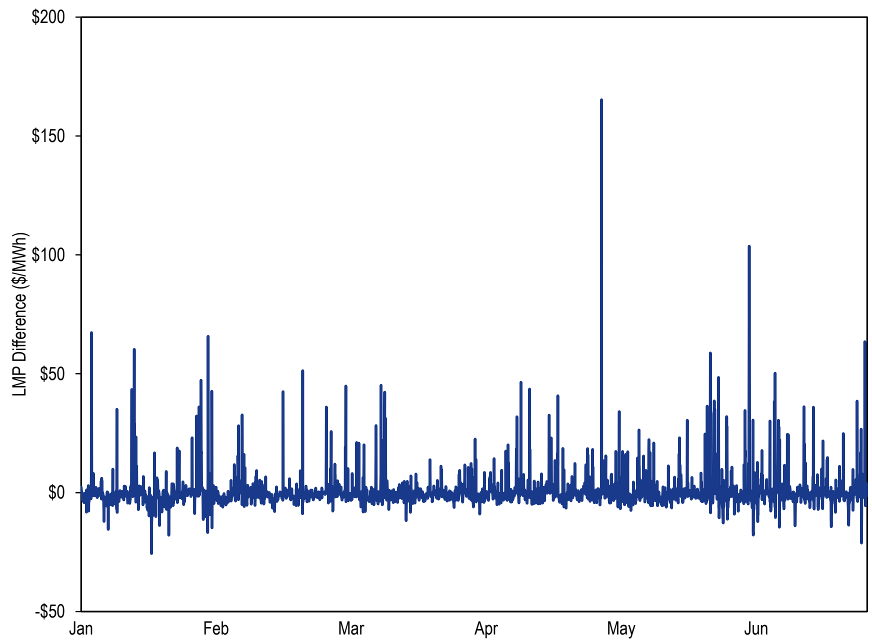
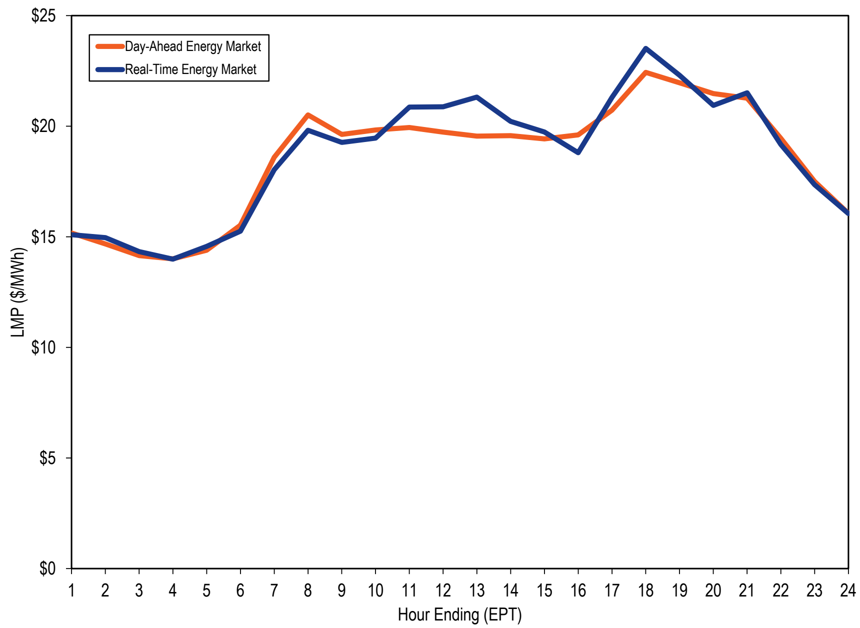


Figure 3-43 shows day-ahead and real-time load-weighted LMP on an average hourly basis for the first six months of 2020. Hour ending 13 had the largest difference between the DA and RT load-weighted LMP, at $1.76 per MWh, and hour ending 24 had the smallest difference at $0.01 per MWh.

Figure 3-43 System hourly average LMP: January through June, 2020



Zonal LMP and Dispatch

Table 3-49 shows zonal real-time, and real-time, load-weighted, average LMP in the first six months of 2019 and 2020.

Table 3-49 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June, 2019 and 2020

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2019 (Jan-Jun)	2020 (Jan-Jun)	Percent Change	2019 (Jan-Jun)	2020 (Jan-Jun)	Percent Change
AECO	$25.82	$17.31	(33.0%)	$26.96	$17.99	(33.3%)
AEP	$26.66	$19.27	(27.7%)	$27.65	$19.93	(27.9%)
APS	$26.71	$19.38	(27.5%)	$27.89	$20.06	(28.1%)
ATSI	$26.86	$19.54	(27.2%)	$27.74	$20.25	(27.0%)
BGE	$28.70	$20.25	(29.4%)	$30.33	$21.29	(29.8%)
ComEd	$24.22	$17.15	(29.2%)	$24.97	$18.01	(27.9%)
DAY	$27.57	$20.14	(27.0%)	$28.67	$20.96	(26.9%)
DEOK	$26.50	$19.33	(27.1%)	$27.46	$20.08	(26.9%)
DLCO	$27.62	$19.54	(29.2%)	$28.93	$20.35	(29.7%)
Dominion	$26.23	$17.38	(33.7%)	$28.29	$18.10	(36.0%)
DPL	$26.37	$19.70	(25.3%)	$27.15	$20.47	(24.6%)
EKPC	$26.26	$19.26	(26.6%)	$27.64	$20.10	(27.3%)
JCPL	$25.75	$17.71	(31.2%)	$27.04	$18.53	(31.5%)
Met-Ed	$26.08	$17.81	(31.7%)	$27.45	$18.57	(32.4%)
OVEC	$25.82	$18.90	(26.8%)	$26.31	$19.08	(27.5%)
PECO	$25.35	$17.04	(32.8%)	$26.53	$17.64	(33.5%)
PENELEC	$25.86	$18.26	(29.4%)	$26.78	$18.81	(29.7%)
Pepco	$27.91	$19.60	(29.8%)	$29.35	$20.55	(30.0%)
PPL	$24.43	$16.95	(30.6%)	$25.71	$17.56	(31.7%)
PSEG	$26.21	$17.52	(33.2%)	$27.34	$18.11	(33.8%)
RECO	$26.21	$17.68	(32.5%)	$27.11	$18.39	(32.2%)
PJM	$26.41	$18.70	(29.2%)	$27.49	$19.40	(29.4%)

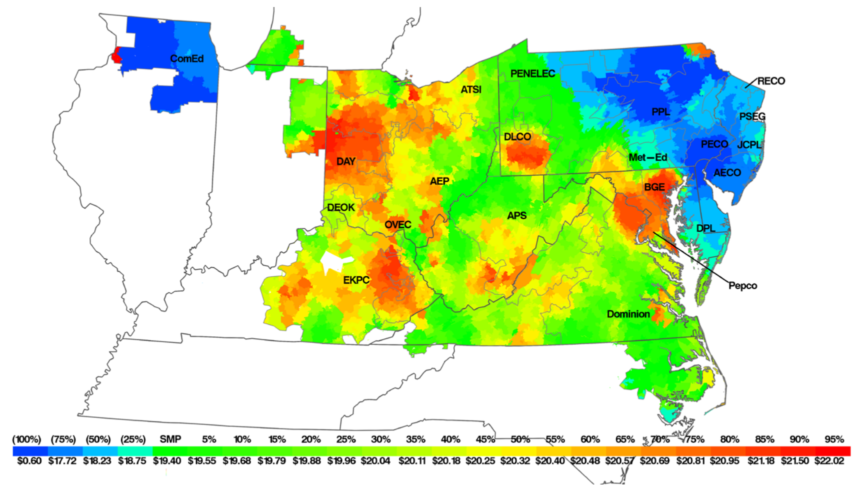
Table 3-50 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first six months of 2019 and 2020.

Table 3-50 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2019 and 2020

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2019 (Jan-Jun)	2020 (Jan-Jun)	Percent Change	2019 (Jan-Jun)	2020 (Jan-Jun)	Percent Change
AECO	$25.87	$16.94	(34.5%)	$26.98	$17.53	(35.0%)
AEP	$27.10	$19.15	(29.3%)	$28.19	$19.81	(29.7%)
APS	$27.32	$19.12	(30.0%)	$28.55	$19.77	(30.7%)
ATSI	$27.58	$19.39	(29.7%)	$28.55	$20.03	(29.9%)
BGE	$29.53	$20.42	(30.8%)	$31.18	$21.45	(31.2%)
ComEd	$24.52	$17.34	(29.3%)	$25.23	$18.08	(28.3%)
DAY	$28.07	$20.13	(28.3%)	$29.19	$20.94	(28.3%)
DEOK	$27.21	$19.38	(28.8%)	$28.27	$20.15	(28.7%)
DLCO	$28.45	$19.31	(32.1%)	$30.05	$20.14	(33.0%)
Dominion	$26.28	$17.30	(34.2%)	$28.27	$18.17	(35.7%)
DPL	$27.01	$19.49	(27.9%)	$27.85	$20.21	(27.4%)
EKPC	$26.56	$19.10	(28.1%)	$28.02	$20.09	(28.3%)
JCPL	$25.67	$17.16	(33.1%)	$26.81	$17.85	(33.4%)
Met-Ed	$25.93	$17.50	(32.5%)	$27.08	$18.19	(32.9%)
OVEC	$26.19	$18.80	(28.2%)	$29.38	$19.52	(33.6%)
PECO	$25.24	$16.67	(33.9%)	$26.28	$17.24	(34.4%)
PENELEC	$26.67	$18.31	(31.3%)	$28.06	$19.05	(32.1%)
Pepco	$28.87	$19.66	(31.9%)	$30.48	$20.65	(32.2%)
PPL	$24.71	$16.70	(32.4%)	$25.85	$17.26	(33.2%)
PSEG	$26.19	$17.18	(34.4%)	$27.27	$17.75	(34.9%)
RECO	$26.61	$17.52	(34.2%)	$27.86	$18.32	(34.3%)
PJM	$26.86	$18.55	(30.9%)	$27.97	$19.23	(31.3%)

Figure 3-44 is a map of the real-time, load-weighted, average LMP in the first six months of 2020. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-44 Real-time, load-weighted, average LMP: January through June, 2020



Net Generation by Zone

Figure 3-45 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2020. Figure 3-45 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-51 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2019 and 2020.

Figure 3-45 Map of real-time generation, less real-time load, by zone: January through June, 2020[55]

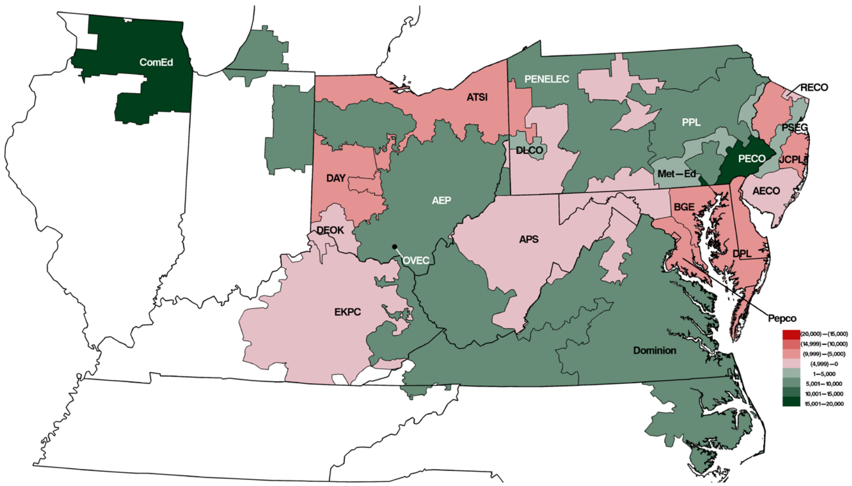


Table 3-51 Real-time generation less real-time load by zone (GWh): January through June, 2019 and 2020

	Zonal Generation and Load (GWh)					
Jan-Jun	2019			2020		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,786.5	4,529.1	(1,742.6)	1,647.5	4,184.7	(2,537.2)
AEP	73,304.8	61,871.9	11,432.9	66,795.0	58,633.4	8,161.6
APS	23,739.4	24,463.4	(724.0)	22,273.9	22,972.4	(698.6)
ATSI	18,985.3	31,778.6	(12,793.4)	20,277.9	30,114.8	(9,836.8)
BGE	8,623.1	15,111.2	(6,488.1)	7,529.4	14,029.0	(6,499.6)
ComEd	66,268.4	44,976.9	21,291.5	62,501.6	43,419.8	19,081.7
DAY	352.0	8,353.2	(8,001.2)	333.0	7,855.2	(7,522.2)
DEOK	9,888.4	12,870.9	(2,982.5)	8,129.8	12,180.4	(4,050.6)
Dominion	47,333.6	48,910.0	(1,576.4)	52,076.6	46,527.4	5,549.2
DPL	2,199.7	8,801.2	(6,601.5)	2,222.6	8,314.2	(6,091.6)
DLCO	8,363.8	6,427.9	1,936.0	7,511.6	6,095.9	1,415.7
EKPC	2,880.6	6,224.8	(3,344.1)	3,405.3	6,037.1	(2,631.8)
JCPL	5,218.4	10,255.2	(5,036.8)	3,706.6	9,813.1	(6,106.5)
Met-Ed	11,175.8	7,584.0	3,591.7	10,300.9	7,188.1	3,112.7
OVEC	5,238.2	66.9	5,171.3	3,931.6	57.9	3,873.8
PECO	34,140.0	19,142.5	14,997.4	36,855.0	17,642.7	19,212.3
PENELEC	20,586.7	8,375.8	12,210.9	17,808.6	8,063.9	9,744.7
Pepco	5,175.5	14,234.2	(9,058.7)	5,291.3	12,832.9	(7,541.6)
PPL	30,431.5	20,080.4	10,351.1	27,329.1	19,152.1	8,177.0
PSEG	21,182.6	20,067.4	1,115.2	20,195.4	19,096.2	1,099.1
RECO	0.0	663.3	(663.3)	0.0	631.1	(631.1)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and

55 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-52 shows PJM generation by fuel source in GWh for the first six months of 2019 and 2020. In the first six months of 2020, generation from coal units decreased 32.1 percent, generation from natural gas units increased 11.7 percent, and generation from oil increased 2.6 percent compared to the first six months of 2019. Wind and solar output rose by 1,375.9 GWh compared to the first six months of 2019, supplying 4.3 percent of PJM energy in the first six months of 2020.

Table 3-52 Generation (By fuel source (GWh)): January through June, 2019 and 2020[56 57 58]

		2019 (Jan - Jun)		2020 (Jan - Jun)		Change in
		GWh	Percent	GWh	Percent	Output
Coal		99,864.3	24.8%	67,845.1	17.6%	(32.1%)
	Bituminous	84,501.8	21.0%	62,576.2	16.2%	(25.9%)
	Sub Bituminous	11,708.4	2.9%	2,840.9	0.7%	(75.7%)
	Other Coal	3,654.1	0.9%	2,428.0	0.6%	(33.6%)
Nuclear		138,609.7	34.4%	136,376.4	35.4%	(1.6%)
Gas		136,016.0	33.8%	151,835.3	39.4%	11.6%
	Natural Gas CC	129,375.4	32.1%	143,212.5	37.2%	10.7%
	Natural Gas CT	4,187.1	1.0%	5,573.6	1.4%	33.1%
	Natural Gas Other Units	1,381.2	0.3%	1,996.8	0.5%	44.6%
	Other Gas	1,072.4	0.3%	1,052.5	0.3%	(1.9%)
Hydroelectric		9,817.5	2.4%	9,155.7	2.4%	(6.7%)
	Pumped Storage	2,188.8	0.5%	2,221.4	0.6%	1.5%
	Run of River	7,002.2	1.7%	6,296.9	1.6%	(10.1%)
	Other Hydro	626.6	0.2%	637.4	0.2%	1.7%
Wind		13,644.9	3.4%	14,497.6	3.8%	6.2%
Waste		2,125.6	0.5%	2,145.3	0.6%	0.9%
Oil		907.5	0.2%	931.5	0.2%	2.6%
	Heavy Oil	6.5	0.0%	0.0	0.0%	(100.0%)
	Light Oil	88.1	0.0%	55.2	0.0%	(37.3%)
	Diesel	65.1	0.0%	9.5	0.0%	(85.4%)
	Other Oil	747.9	0.2%	866.8	0.2%	15.9%
Solar, Net Energy Metering		1,349.6	0.3%	1,872.7	0.5%	38.8%
Battery		10.9	0.0%	17.1	0.0%	55.9%
Biofuel		592.1	0.1%	438.4	0.1%	(26.0%)
Total		402,938.1	100.0%	385,115.0	100.0%	(4.4%)

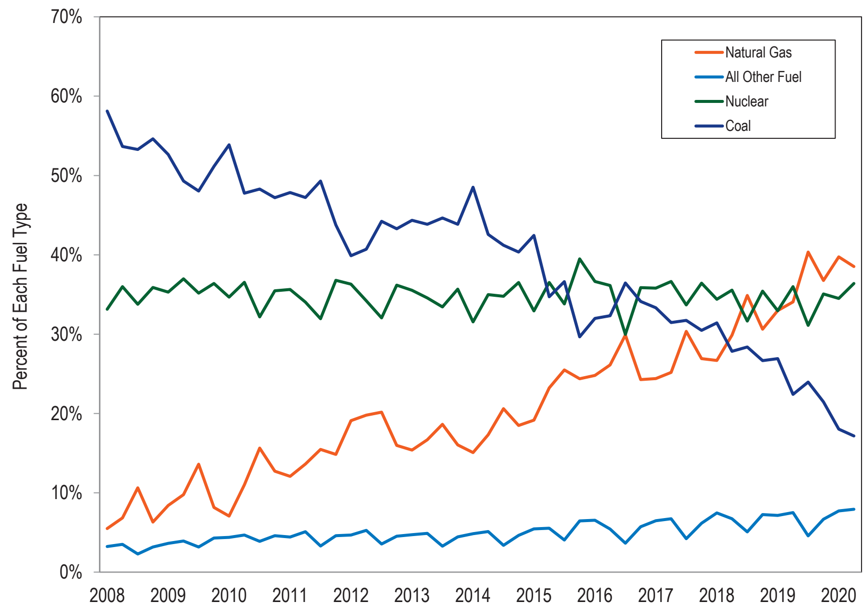
56 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.
57 Net Energy Metering is combined with Solar due to data confidentiality reasons.
58 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-53 Monthly generation (By fuel source (GWh)): January through June, 2020

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	13,301.6	12,829.4	9,998.2	7,986.2	9,746.6	13,983.2	67,845.1
Bituminous	12,414.8	11,741.5	9,255.7	7,144.5	9,154.6	12,865.0	62,576.2
Sub Bituminous	348.1	570.5	340.4	452.2	295.2	834.4	2,840.9
Other Coal	538.6	517.3	402.2	389.5	296.8	283.7	2,428.0
Nuclear	25,012.5	22,067.6	22,062.1	20,904.1	22,691.8	23,638.2	136,376.4
Gas	28,107.6	25,976.7	26,074.6	21,799.1	21,613.3	28,264.2	151,835.3
Natural Gas CC	26,839.6	25,157.8	25,188.7	20,970.9	20,094.7	24,960.9	143,212.5
Natural Gas CT	736.3	482.7	614.0	544.9	1,029.3	2,166.3	5,573.6
Natural Gas Other Units	343.8	159.1	83.4	108.3	314.3	987.9	1,996.8
Other Gas	187.9	177.1	188.6	174.9	174.9	149.1	1,052.5
Hydroelectric	1,474.0	1,558.7	1,489.8	1,410.3	1,651.6	1,571.4	9,155.7
Pumped Storage	370.7	309.2	324.9	273.5	447.8	495.3	2,221.4
Run of River	1,014.4	1,127.3	1,082.5	1,078.5	1,085.5	908.7	6,296.9
Other Hydro	88.9	122.2	82.4	58.3	118.3	167.4	637.4
Wind	2,589.6	2,564.5	2,739.5	2,679.8	2,261.8	1,662.4	14,497.6
Waste	366.3	297.0	391.2	357.9	380.3	352.5	2,145.3
Oil	128.2	159.1	165.2	160.2	152.9	165.9	931.5
Heavy Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light Oil	10.8	6.4	2.2	2.2	3.7	29.9	55.2
Diesel	7.5	0.2	0.3	0.1	0.0	1.5	9.5
Other Oil	109.9	152.6	162.8	157.9	149.2	134.5	866.8
Solar, Net Energy Metering	187.3	208.8	288.5	363.0	401.1	424.0	1,872.7
Battery	2.0	2.4	3.6	3.0	3.0	3.1	17.1
Biofuel	84.7	101.9	102.2	36.6	46.8	66.2	438.4
Total	71,253.7	65,766.2	63,314.9	55,700.0	58,949.2	70,131.1	385,115.0

Figure 3-46 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Figure 3-46 Share of generation by fuel source: January 2008 through June 2020



Fuel Diversity

Figure 3-47 shows the fuel diversity index (FDI_e) for PJM energy generation.[59] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-53 with nonzero generation values. As fuel diversity has

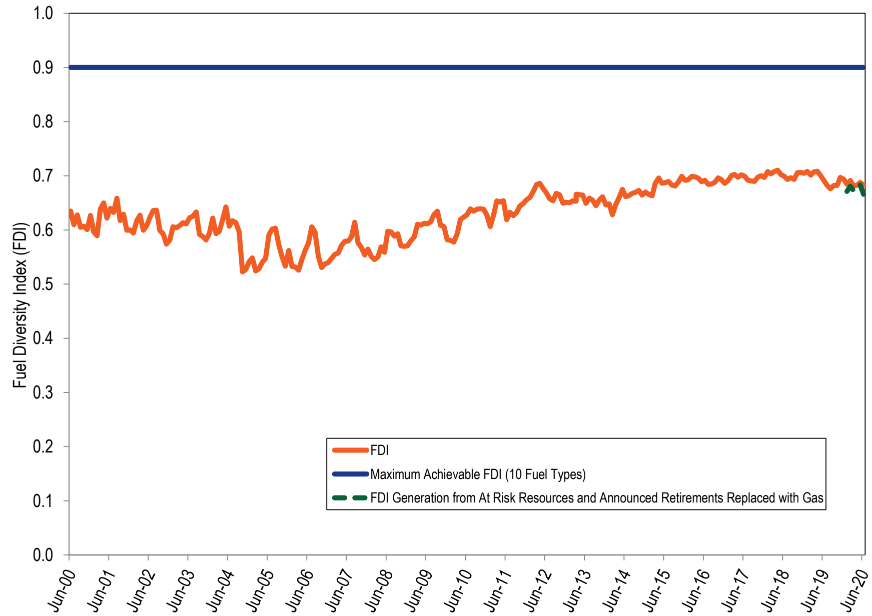
59 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 35.4 percent from 2012 through 2019. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[60] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent for 2008 and 17.6 percent for the first six months of 2020. Gas generation as a share of total generation was 7.4 percent for 2008 and 39.4 percent for the first six months of 2020. Wind generation as a share of total generation was 0.5 percent for 2008 and 3.8 percent for the first six months of 2020.

The average FDI_e decreased 2.5 percent for the first six months of 2020 compared to the first six months of 2019. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 9,543.0 MW of coal, CT, diesel, and nuclear capacity were identified as being at risk of retirement.[61] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[62] There are 4,027.5 MW of generation that have requested retirement after June 30, 2020.[63] The at risk units and other generators with deactivation notices generated 14,645.0 GWh in the first six months of 2020.[64] The dashed line in Figure 3-47 shows a counterfactual result for FDI_e assuming the 14,645.0 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas generation. The FDI_e for the first six months of 2020 under the counterfactual assumption would have been 1.4 percent lower than the actual FDI_e.

60 See the *2019 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.
61 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.
62 See PJM. OATT: § V "Generation Deactivation."
63 See *2020 Quarterly State of the Market Report for PJM: January through June*, Section 12: Generation and Transmission Planning, Table 12-9.
64 Previous state of the market reports incorrectly reported the generation by the at risk units and generators with deactivation notices in TWh rather than GWh.

Figure 3-47 Fuel diversity index for monthly generation: June 2000 through June 2020



Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-54 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first six months of 2020, coal units were 16.4 percent and natural gas units were 74.0 percent of marginal resources. In the first six months of 2020, natural gas combined cycle units were 70.1 percent of marginal resources. In the first six months of 2019, coal units were 26.6 percent and natural gas units were 68.1 percent of the total marginal resources. In the first six months of 2019, natural gas combined cycle units were 63.1 percent of the total marginal resources. In the first six months of 2020, 95.8 percent of the wind marginal units had negative offer prices, 4.2 percent had zero offer prices and none had positive offer prices. In the first six month of 2019, 91.8 percent of the wind marginal units had negative offer prices, 8.2 percent had zero offer prices and none had positive offer prices.

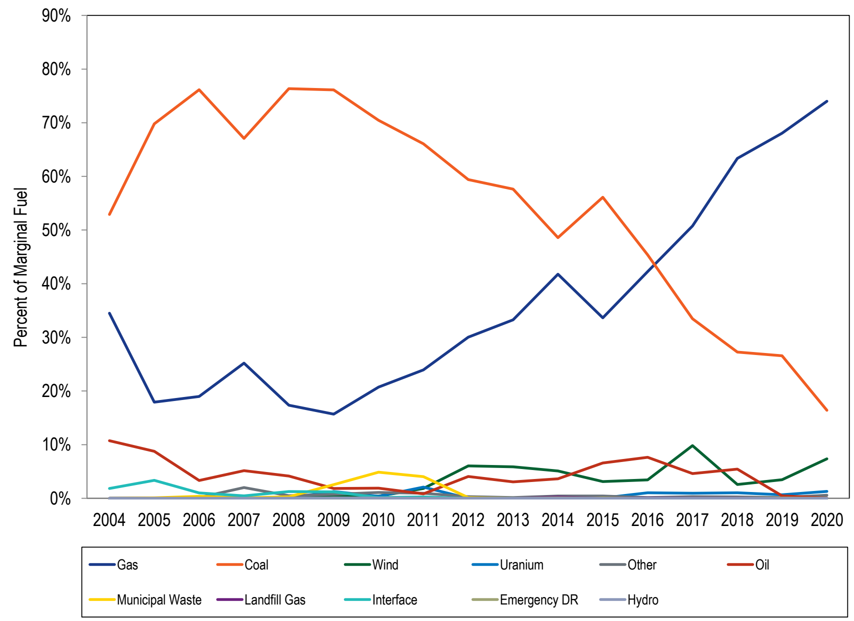
The proportion of marginal nuclear units increased from 0.67 percent in the first six months of 2019 to 1.29 percent in the first six months of 2020. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-54 Type of fuel used and technology (By real-time marginal units): January through June, 2016 through 2020[65]

		(Jan - Jun)				
Fuel	Technology	2016	2017	2018	2019	2020
Gas	CC	31.50%	44.11%	53.45%	63.09%	70.12%
Coal	Steam	45.38%	33.47%	27.26%	26.57%	16.41%
Wind	Wind	3.43%	9.81%	2.56%	3.47%	7.36%
Gas	CT	5.96%	3.78%	7.80%	4.19%	2.90%
Uranium	Steam	1.03%	0.96%	1.04%	0.67%	1.29%
Gas	Steam	4.70%	2.56%	1.68%	0.77%	0.99%
Other	Solar	0.03%	0.15%	0.12%	0.07%	0.51%
Other	Steam	0.12%	0.16%	0.15%	0.07%	0.06%
Oil	CT	7.16%	4.24%	4.58%	0.43%	0.05%
Municipal Waste	Steam	0.01%	0.01%	0.04%	0.03%	0.01%
Landfill Gas	CT	0.01%	0.00%	0.02%	0.01%	0.01%
Oil	Steam	0.06%	0.01%	0.29%	0.01%	0.01%
Oil	RICE	0.38%	0.37%	0.42%	0.00%	0.00%
Oil	CC	0.04%	0.00%	0.13%	0.03%	0.00%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.01%	0.01%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.04%	0.02%	0.00%	0.00%	0.00%
Gas	RICE	0.10%	0.30%	0.41%	0.00%	0.00%

Figure 3-48 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-48 Type of fuel used (By real-time marginal units): January through June, 2004 through 2020



65 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-55 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In the first six months of 2020, up to congestion transactions were 52.3 percent of marginal resources. Up to congestion transactions were 57.8 percent of marginal resources in the first six months of 2019.

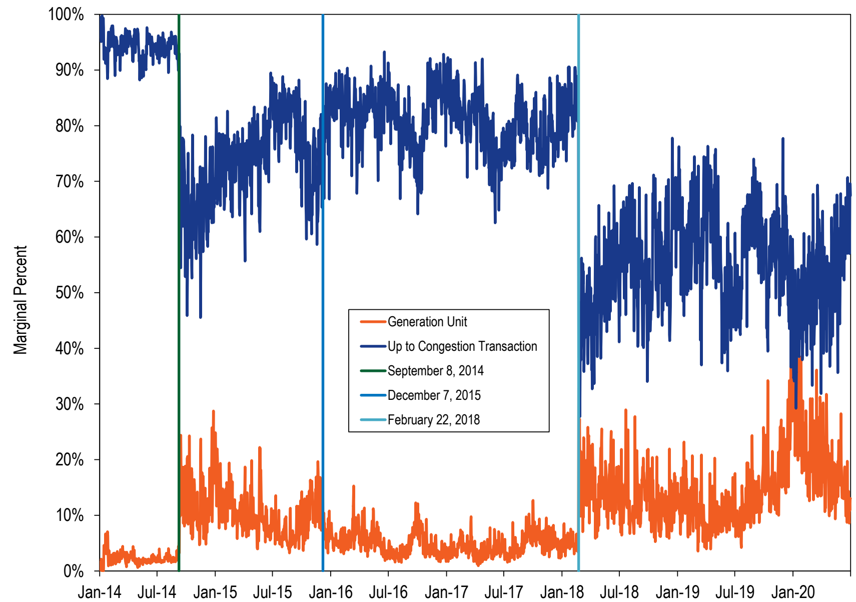
Table 3-55 Day-ahead marginal resources by type/fuel used and technology: January through June, 2016 through 2020

		(Jan - Jun)				
Type/Fuel	Technology	2016	2017	2018	2019	2020
Up to Congestion Transaction	NA	82.54%	80.59%	66.89%	57.80%	52.29%
INC	NA	3.76%	5.33%	8.38%	13.33%	14.26%
DEC	NA	7.23%	9.63%	14.65%	18.22%	14.21%
Gas	CC	2.63%	1.94%	4.91%	5.80%	12.66%
Coal	Steam	2.59%	1.61%	4.15%	4.19%	5.32%
Wind	Wind	0.05%	0.23%	0.18%	0.11%	0.40%
Gas	Steam	0.45%	0.32%	0.26%	0.26%	0.31%
Uranium	Steam	0.06%	0.03%	0.08%	0.02%	0.23%
Other	Steam	0.01%	0.00%	0.01%	0.01%	0.09%
Gas	CT	0.04%	0.04%	0.17%	0.07%	0.08%
Dispatchable Transaction	NA	0.06%	0.03%	0.11%	0.11%	0.07%
Oil	CT	0.56%	0.21%	0.04%	0.01%	0.03%
Other	Solar	0.00%	0.00%	0.03%	0.01%	0.02%
Gas	RICE	0.00%	0.02%	0.04%	0.04%	0.02%
Municipal Waste	RICE	0.01%	0.00%	0.00%	0.01%	0.01%
Oil	Steam	0.00%	0.00%	0.05%	0.00%	0.00%
Oil	RICE	0.00%	0.02%	0.00%	0.00%	0.00%
Oil	CC	0.00%	0.00%	0.03%	0.00%	0.00%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.00%
Price Sensitive Demand	NA	0.00%	0.00%	0.01%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-49 shows, for the day-ahead energy market from January 2014 through June 2020, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 57.8 percent in the first six months of 2019 to 52.3 percent in the first six months of 2020.

The average number of up to congestion bids submitted in the day-ahead energy market increased by 9.9 percent, from 47,989 bids per day in the first six months of 2019 to 52,781 bids per day in the first six months of 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 5.8 percent, from 497,987 MWh per day in the first six months of 2019, to 469,113 MWh per day in the first six months of 2020.

Figure 3-49 Day-ahead marginal up to congestion transaction and generation units: January 2014 through June 2020

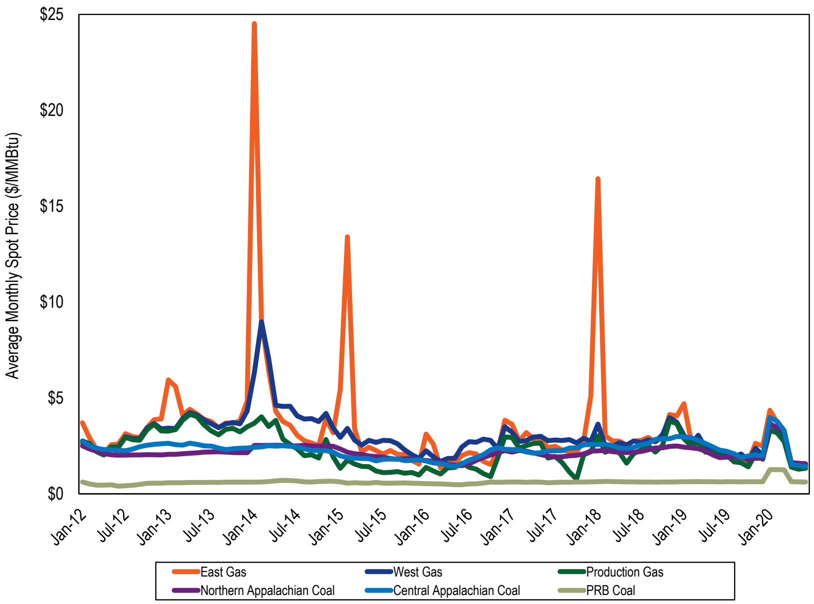


Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-50 shows fuel prices in PJM for 2012 through the first six months of 2020. Natural gas prices decreased in the first six months of 2020 compared to the first six months of 2019. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new combined cycle plants have located in the production area since 2016. In the first six months of 2020, the price of production gas was 7.9 percent lower than in the first six months of 2019. The price of eastern natural gas was 9.5 percent lower and the price of western natural gas was 4.6 percent lower. The price of Northern Appalachian coal was 13.5 percent higher; the price of Central Appalachian coal was 3.4 percent lower; and the price of Powder River Basin coal was 48.7 percent higher.[66] The price of ULSD NY Harbor Barge was 44.2 percent lower.

Figure 3-50 Spot average fuel price comparison: January 2012 through June 2020 ($/MMBtu)



66 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Table 3-56 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in the first six months of 2020 to the load-weighted, average LMP in the first six months of 2019.[67] The real-time, load-weighted average LMP in the first six months of 2020 decreased by $8.09 or -29.4 percent from the real-time load-weighted, average LMP in the first six months of 2019. The real-time load-weighted, average LMP for the first six months of 2020 was 17.6 percent lower than the real-time fuel-cost adjusted, load-weighted average LMP for the first six months of 2020. The real-time, fuel-cost adjusted, load-weighted average LMP for the first six months of 2020 was 14.3 percent lower than the real-time load-weighted, average LMP for the first six months of 2019. If fuel and emissions costs in the first six months of 2020 had been the same as in the first six months of 2019, holding the market dispatch constant, the real-time, load-weighted, average LMP in the first six months of 2020 would have been higher, $23.55 per MWh, than the observed $19.40 per MWh. Only 51.3 percent of the decrease in real-time, load-weighted, average LMP, $4.15 per MWh out of $8.09 per MWh, is directly attributable to fuel costs. Contributors to the other $3.94 per MWh are decreased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

Table 3-56 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through June, 2019 and 2020

	2020 Fuel-Cost Adjusted, Load-Weighted LMP	2020 Load-Weighted LMP	Change	Percent Change
Average	$23.55	$19.40	($4.15)	(17.6%)
	2019 Load-Weighted LMP	2020 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$27.49	$23.55	($3.94)	(14.3%)
	2019 Load-Weighted LMP	2020 Load-Weighted LMP	Change	Change
Average	$27.49	$19.40	($8.09)	(29.4%)

Table 3-57 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first six months of 2020. Table 3-57 shows that lower natural gas prices explain 90.8 percent of the fuel-cost related decrease in the real-time annual,

67 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

load-weighted average LMP in the first six months of 2020 from the first six months of 2019.

Table 3-57 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: January through June, 2020 adjusted to 2019 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	($3.77)	90.8%
Coal	($0.37)	8.9%
Oil	($0.01)	0.3%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	($4.15)	100.0%

Components of LMP

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and ten minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, and New Jersey.[68] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

68 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-58 shows the frequency and average shadow price of transmission constraints in PJM. In the first six months of 2020, there were 83,248 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly two percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[69] In the first six months of 2020, the average shadow price of transmission constraints when the line limit was violated was nearly 27.4 times higher than when the transmission constraint was binding at its limit.

69 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

Table 3-58 Frequency and average shadow price of transmission constraints: January through June, 2019 and 2020

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2019 (Jan - Jun)	2020 (Jan - Jun)	2019 (Jan - Jun)	2020 (Jan - Jun)
PJM Internal Violated Transmission Constraints	2,651	1,289	$1,312.35	$1,745.42
PJM Internal Binding Transmission Constraints	37,176	64,364	$105.79	$63.68
Market to Market Transmission Constraints	20,935	17,595	$203.49	$238.31
All Transmission Constraints	60,762	83,248	$192.09	$126.63

Transmission penalty factors should be applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. PJM continues the practice of discretionary reduction in line ratings.

Table 3-59 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM real-time market. In the first six months of 2020, there were 1,085 or 84 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor equal to the default $2,000 per MWh.

Table 3-59 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Internal Violated Transmission Constraints	1,619	36	996	1,085	-	204
PJM Internal Binding Transmission Constraints	34,374	664	2,138	59,378	-	4,986
Market to Market Transmission Constraints	4,638	3	16,294	1,430	-	16,165
All Transmission Constraints	40,631	703	19,428	61,893	-	21,355

The components of LMP are shown in Table 3-60, including markup using unadjusted cost-based offers.[70] Table 3-60 shows that in the first six months of 2020, 29.1 percent of the load-weighted LMP was the result of coal costs, 43.3 percent was the result of gas costs and 1.8 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, markup was 1.8 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first six months of 2020 and the first six months of 2019.

70 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-60 Components of real-time (Unadjusted), load-weighted, average LMP: January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$12.45	45.3%	$8.39	43.3%	(2.0%)
Coal	$7.30	26.6%	$5.66	29.1%	2.6%
Ten Percent Adder	$2.15	7.8%	$1.58	8.2%	0.3%
VOM	$1.54	5.6%	$1.41	7.3%	1.6%
Constraint Violation Adder	$1.19	4.3%	$0.77	4.0%	(0.4%)
NA	$0.10	0.4%	$0.53	2.7%	2.3%
CO_2 Cost	$0.21	0.8%	$0.36	1.8%	1.1%
Markup	$1.71	6.2%	$0.34	1.8%	(4.4%)
LPA Rounding Difference	$0.19	0.7%	$0.22	1.1%	0.4%
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.0%)
Scarcity Adder	$0.25	0.9%	$0.03	0.2%	(0.7%)
Oil	$0.02	0.1%	$0.03	0.1%	0.1%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.03	0.1%	(0.7%)
Opportunity Cost Adder	$0.04	0.1%	$0.02	0.1%	(0.0%)
LPA-SCED Differential	$0.00	0.0%	$0.01	0.1%	0.0%
NO_x Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Landfill Gas	$0.00	0.0%	($0.01)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.02)	(0.1%)	(0.1%)
Total	$27.49	100.0%	$19.40	100.0%	0.0%

Table 3-61 Components of real-time (Adjusted), load-weighted, average LMP: January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$12.45	45.3%	$8.39	43.3%	(2.0%)
Coal	$7.30	26.6%	$5.66	29.1%	2.6%
Markup	$3.86	14.1%	$1.93	9.9%	(4.1%)
VOM	$1.54	5.6%	$1.41	7.3%	1.6%
Constraint Violation Adder	$1.19	4.3%	$0.77	4.0%	(0.4%)
NA	$0.10	0.4%	$0.53	2.7%	2.3%
CO_2 Cost	$0.21	0.8%	$0.36	1.8%	1.1%
LPA Rounding Difference	$0.19	0.7%	$0.22	1.1%	0.4%
Increase Generation Adder	$0.10	0.4%	$0.06	0.3%	(0.0%)
Scarcity Adder	$0.25	0.9%	$0.03	0.2%	(0.7%)
Oil	$0.02	0.1%	$0.03	0.1%	0.1%
Ancillary Service Redispatch Cost	$0.24	0.9%	$0.03	0.1%	(0.7%)
Opportunity Cost Adder	$0.04	0.1%	$0.02	0.1%	(0.0%)
LPA-SCED Differential	$0.00	0.0%	$0.01	0.1%	0.0%
NO_x Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Market-to-Market Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Renewable Energy Credits	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Landfill Gas	$0.00	0.0%	($0.01)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.02)	(0.1%)	(0.1%)
Total	$27.49	100.0%	$19.40	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-60 and Table 3-62), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-61 and Table 3-63), the 10 percent markup is removed from the cost-based offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-61, including markup using adjusted cost-based offers.

Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Table 3-62 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2020, 31.2 percent of the load-weighted LMP was the result of coal costs, 19.4 percent of the load-weighted LMP was the result of gas costs, 18.4 percent was the result of DEC bid costs, 14.0 percent was the result of INC bid costs and 3.2 percent was the result of the up to congestion transaction costs.

Table 3-62 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.53	23.4%	$6.01	31.2%	7.9%
Gas	$5.83	20.8%	$3.72	19.4%	(1.5%)
DEC	$5.71	20.4%	$3.55	18.4%	(2.0%)
INC	$5.73	20.5%	$2.69	14.0%	(6.5%)
VOM	$1.22	4.4%	$1.16	6.1%	1.7%
Ten Percent Cost Adder	$1.37	4.9%	$1.12	5.8%	0.9%
Up to Congestion Transaction	$0.60	2.1%	$0.62	3.2%	1.1%
CO_2	$0.13	0.5%	$0.27	1.4%	1.0%
Dispatchable Transaction	$0.35	1.3%	$0.09	0.5%	(0.8%)
Constrained Off	($0.02)	(0.1%)	$0.07	0.4%	0.4%
DASR LOC Adder	$0.00	0.0%	$0.01	0.0%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Oil	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Markup	$0.48	1.7%	($0.14)	(0.7%)	(2.4%)
Price Sensitive Demand	$0.02	0.1%	$0.00	0.0%	(0.1%)
NA	$0.00	0.0%	$0.04	0.2%	0.2%
Total	$27.97	100.0%	$19.23	100.0%	(0.0%)

Table 3-63 shows the components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-63 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.53	23.4%	$6.01	31.2%	7.9%
Gas	$5.83	20.8%	$3.72	19.4%	(1.5%)
DEC	$5.71	20.4%	$3.55	18.4%	(2.0%)
INC	$5.73	20.5%	$2.69	14.0%	(6.5%)
VOM	$1.22	4.4%	$1.16	6.1%	1.7%
Markup	$1.83	6.5%	$0.99	5.1%	(1.4%)
Up to Congestion Transaction	$0.60	2.1%	$0.62	3.2%	1.1%
CO_2	$0.13	0.5%	$0.27	1.4%	1.0%
Dispatchable Transaction	$0.35	1.3%	$0.09	0.5%	(0.8%)
Constrained Off	($0.02)	(0.1%)	$0.07	0.4%	0.4%
DASR LOC Adder	$0.00	0.0%	$0.01	0.0%	0.0%
NO_x	$0.01	0.0%	$0.01	0.0%	(0.0%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Ten Percent Cost Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Municipal Waste	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Oil	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Price Sensitive Demand	$0.02	0.1%	$0.00	0.0%	(0.1%)
NA	$0.00	0.0%	$0.04	0.2%	0.2%
Total	$27.97	100.0%	$19.23	100.0%	(0.0%)

Scarcity

PJM's energy market experienced five minute shortage pricing for two five minute intervals on one day in the first six months of 2020. Table 3-64 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2019 and 2020. In the first six months of 2020, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The day with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-64 Summary of emergency events declared: January through June, 2019 and 2020

	Number of days events declared	
Event Type	Jan - Jun, 2019	Jan - Jun, 2020
Cold Weather Alert	9	3
Hot Weather Alert	3	2
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	11	1
Energy export recalls from PJM capacity resources	0	0

Figure 3-51 shows the number of days that weather and capacity emergency alerts were issued in PJM during the first six months from 2016 through 2020. Figure 3-52 shows the number of days emergency warnings were issued or actions taken in PJM during the first six months from 2016 through 2020.

Figure 3-51 Declared emergency alerts: January through June, 2016 through 2020

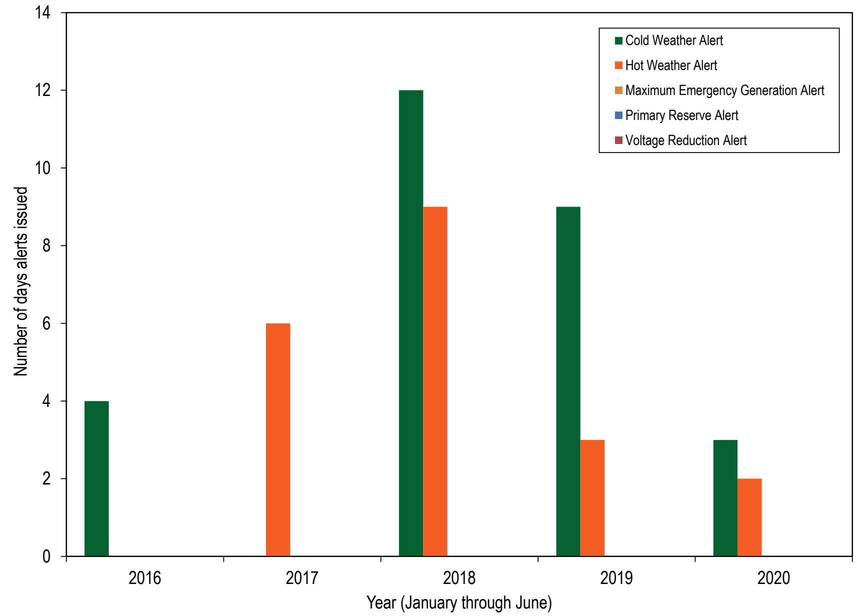
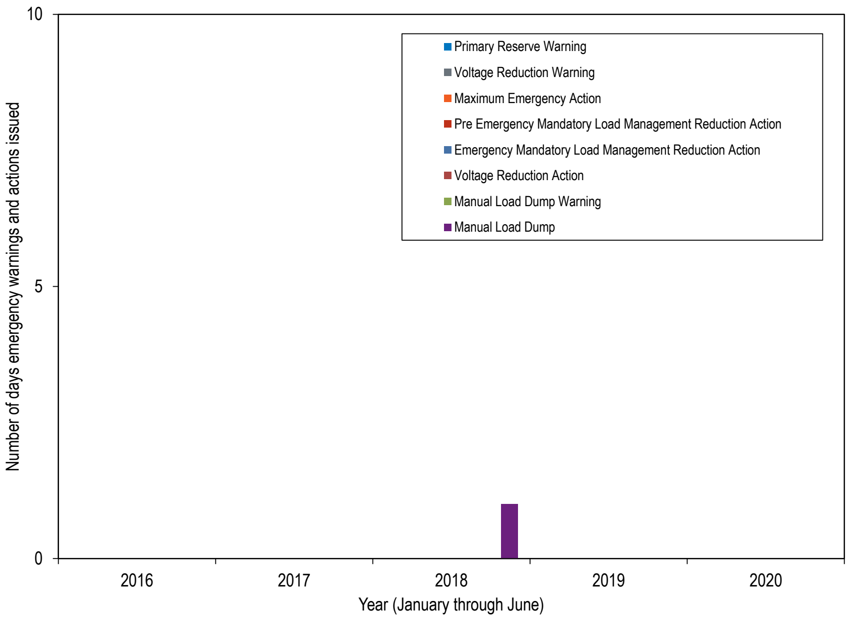


Figure 3-52 Declared emergency warnings and actions: January through June, 2016 through 2020



Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time, on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

Table 3-65 provides a description of PJM declared emergency procedures.[71 72 73 74]

Table 3-65 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

71 See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 3.3 Cold Weather Alert.
72 See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 3.4 Hot Weather Alert.
73 See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
74 See PJM. "Manual 13: Emergency Operations," Rev. 76 (March 26, 2020), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-66 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2020.

Table 3-66 Declared emergency alerts, warnings and actions: January through June, 2020

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
1/19/2020	ComEd													
1/20/2020	ComEd													
1/21/2020	ComEd													
6/22/2020		Mid-Atlantic												
6/23/2020		Mid-Atlantic and Dominion												

Power Balance Constraint Violation

On October 1, 2019, in 11 approved RT SCED solutions between 1455 EPT and 1655 EPT, the power balance constraint in RT SCED was violated. On February 16, 2020, in one approved RT SCED solution, the power balance constraint in RT SCED was violated. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by ASO to energy to satisfy the power balance constraint.[75] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to scarcity pricing.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.

75 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Table 3-67 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. Subsequently, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first six months of 2020, there were four five minute intervals using RT SCED solutions with violated power balance constraint.

Table 3-67 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals
2013	-
2014	655
2015	71
2016	42
2017	31
2018	16
2019	36
2020	4

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response.[76] It is not appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 delivery year.[77] These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the calculation of the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level.

76 *2018 State of the Market Report for PJM*: Volume 2, Section 3: Energy Market, at Scarcity, pp. 201 – 202.
77 *See* PJM, "Capacity Market Seller Offer Cap Values", (March 15, 2019), *which can be accessed at* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Scarcity pricing is a mechanism for signaling scarcity conditions through energy prices. Under the PJM rules that were in place through September 30, 2012, scarcity pricing resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing. Shortage pricing is an administrative scarcity pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real time reserves than required.

In the first six months of 2020, there were two five minute intervals with shortage pricing in PJM.

With Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[78] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage

78 155 FERC ¶ 61,276 ("Order No. 825") at P 162.

pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. PJM did not implement the rule as intended in Order No. 825. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.[79]

PJM Tariff Revisions to Operating Reserve Demand Curves

On May 12, 2017, PJM submitted tariff revisions to reflect changes to the Operating Reserve Demand Curves (ORDC) used in the real-time energy market to price shortage of primary reserves and synchronized reserves.[80] The updates to the ORDC went into effect on July 12, 2017.

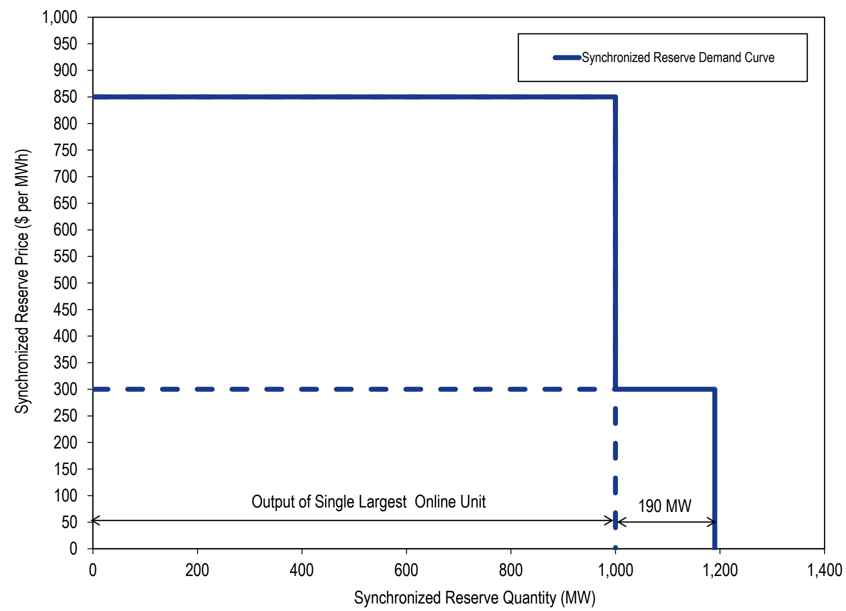
PJM revised the synchronized reserve requirement in a reserve zone or a subzone from the economic maximum of the largest unit on the system to 100 percent of the actual output of the single largest online unit in that reserve zone or subzone. PJM revised the primary reserve requirement in a reserve zone or a subzone from 150 percent of the economic maximum of the largest unit on the system to 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step continues to be priced at $850 per MWh.

79 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21-30:14 (Oct. 28, 2014).

80 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

PJM also added a permanent second step to the primary and synchronized reserve demand curves, set at the extended primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-53 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

Figure 3-53 Updated synchronized reserve demand curve showing the permanent second step



Scarcity Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-53 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves than required.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO Reserve Zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. However, in real-time operations, due to generator outages, transmission outages, and local weather patterns, PJM may need to maintain or operate resources in other local areas to maintain local reliability, in addition to the RTO and MAD reserve levels. Currently, these units are committed out of market for reliability reasons, or are modeled as artificial closed loop interfaces with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. Instead, the new ORDC will be inflated at all times based on average historical forecast error that may or may not have resulted in operator actions to commit additional reserves.

Reserve Shortages in 2020

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solved cases to determine how many of the solved RT SCED cases indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), how many of these solved cases were approved by PJM, and how many of these were used in LPC to calculate prices. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval was less than the extended reserve requirement. Table 3-68 shows the number and percent of RT SCED cases solved that indicated a shortage of any of the four reserve products (RTO synchronized reserve, RTO primary reserve, MAD synchronized reserve, and MAD primary reserve), the number and percent of the solved RT SCED cases with shortage that were approved by PJM, and the number and percent of the RT SCED cases with shortage that were used in LPC to calculate real-time prices.

Table 3-68 shows that, in the first six months of 2020, PJM operators approved two RT SCED cases that indicated a shortage of reserves, from a total of 1,561 RT SCED solutions that indicated shortage. Among the two approved RT SCED solutions with reserve shortage, only one was used in LPC for LMPs and reserve clearing prices. The single shortage case was used in LPC for two consecutive five minute intervals. In comparison, in the first six months of 2019, PJM operators approved 28 cases that indicated a shortage of reserves, from a total of 2,718 RT SCED solutions that indicated shortage. It is unclear what criteria PJM operators use to approve the RT SCED solutions to send dispatch signals to resources. The RT SCED approval process remains inconsistent and undefined.

Table 3-68 RT SCED cases with reserve shortage: January through June, 2020

Month (2020)	Number of Solved RT SCED Cases	Number of Solved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage Used in LPC	Cases With Reserve Shortage as Percent of Solved RT SCED Cases	Approved RT SCED Cases With Reserve Shortage as Percent of Solved RT SCED Cases With Shortage	RT SCED Cases With Shortage Used in LPC as Percent of Solved RT SCED Cases With Shortage
Jan	51,022	337	0	0	0.7%	0.0%	0.0%
Feb	46,247	186	0	0	0.4%	0.0%	0.0%
Mar	38,680	282	0	0	0.7%	0.0%	0.0%
Apr	36,543	420	2	1	1.1%	0.5%	0.2%
May	36,648	167	0	0	0.5%	0.0%	0.0%
Jun	34,327	169	0	0	0.5%	0.0%	0.0%
Total	243,467	1,561	2	1	0.6%	0.1%	0.1%

While there were 1,561 RT SCED solutions that indicated shortage, the number of RT SCED target times for which RT SCED indicated shortage was only 874. This is because PJM solves multiple RT SCED cases with three solutions per case, for each five minute target time.[81]

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-69 shows, for each month of 2020, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Table 3-69 shows that 874 target times, or 1.7 percent of all five minute target times in the first six months of 2020, had at least one RT SCED solution showing a shortage of reserves, and 364 target times, or 0.7 percent of all five minute target times in the first six months of 2020, had more than one RT SCED solution showing a shortage of reserves.

Table 3-69 Five minute intervals with shortage: January through June, 2019 and 2020

Year, Month	Number of Five Minute Intervals	Number of Intervals With At Least One Solved SCED Case Short of Reserves	Percent Intervals With At Least One Solved SCED Case Short of Reserves	Number of Intervals With Multiple Solved SCED Cases Short of Reserves	Percent Intervals With Multiple Solved SCED Cases Short of Reserves	Number of Intervals With Five Minute Shortage Prices in LPC	Percent Intervals With Five Minute Shortage Prices in LPC
2019 Jan	8,928	87	1.0%	34	0.4%	3	0.0%
2019 Feb	8,064	185	2.3%	79	1.0%	0	0.0%
2019 Mar	8,916	350	3.9%	175	2.0%	10	0.1%
2019 Apr	8,640	424	4.9%	217	2.5%	7	0.1%
2019 May	8,928	203	2.3%	94	1.1%	0	0.0%
2019 Jun	8,640	233	2.7%	93	1.1%	0	0.0%
2019 Jan - Jun	52,116	1,482	2.8%	692	1.3%	20	0.0%
2020 Jan	8,928	172	1.9%	89	1.0%	0	0.0%
2020 Feb	8,352	94	1.1%	44	0.5%	0	0.0%
2020 Mar	8,916	173	1.9%	66	0.7%	0	0.0%
2020 Apr	8,640	208	2.4%	99	1.1%	2	0.0%
2020 May	8,928	113	1.3%	36	0.4%	0	0.0%
2020 Jun	8,640	114	1.3%	30	0.3%	0	0.0%
2020 Jan - Jun	52,404	874	1.7%	364	0.7%	2	0.0%

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

While a single RT SCED solution indicating a shortage for a target time among multiple RT SCED solutions that solved for that target time could be the result of operator load bias or erroneous inputs, it is less likely that a target time with multiple RT SCED solutions indicating shortage was the result of an error. There were two five minute intervals with shortage pricing that occurred in the first six months of 2020, while there were 364 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In the first six months of 2019, out of 1,482 target times for which one or more RT SCED solutions indicated a shortage of reserves, there were 20 five minute intervals, or 1.3 percent, with shortage pricing. In the first six months of 2020, out of 874 intervals for which one or more RT SCED solutions indicated a shortage of reserves, there were two five minute intervals, or 0.2 percent, with shortage pricing.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. 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. The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources, and for pricing, to minimize operator discretion and implement a rule based approach.

Shortage Pricing Intervals in LPC

There were two five minute intervals with shortage pricing in the first six months of 2020, compared to 20 intervals in the first six months of 2019, in PJM. In both intervals on April 30, 2020, shortage pricing was triggered only due to synchronized reserves at the RTO level being short of the extended synchronized reserve requirement. Table 3-70 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the intervals with shortage pricing. The clearing price for synchronized reserves during these intervals, at $850 per MWh, reflects the maximum price in the ORDC for synchronized reserves in the RTO Zone.

Table 3-70 RTO Synchronized Reserve Shortage Intervals: January through June, 2020

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
30-Apr-20 12:05	1,817.2	1,614.6	202.6	$850.0
30-Apr-20 12:10	1,817.2	1,614.6	202.6	$850.0

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as tier 1 bias or operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[82] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. 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. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators

82 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

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's generator models do not account for 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 generator parameters, called Degree of Generator Performance (DGP).[83] [84] 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.

PJM adjusts ramp rates using DGP, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Natural Gas Pipeline Issues

In 2019 and the first six months of 2020, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. These notices may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrates the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

The increase in natural gas fired capacity in PJM in recent years also highlighted issues with the dependence of the PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, creates risks for the bulk power system. PJM should collect data on each individual generator's fuel supply arrangements, and analyze the associated locational and regional risks to reliability.

Competitive Assessment

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first six months of 2020 indicates low concentration in the base load segment,

83 *See* "PJM Manual 12: Balancing Operations," Rev. 40 (March 26, 2020) Attachment A, P78. "PJM Manual 11: Energy and Ancillary Services Market Operations," does not mention the use of DGP in the market clearing engine.

84 PJM published a whitepaper that defines DGP and describes its use, which can be accessed at <http://www.pjm.com/~/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx> (July 2, 2020).

moderate concentration in the intermediate segment, and high concentration in the peaking segment.[85] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first six months of 2020, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

The Herfindahl-Hirschman Index (HHI) concentration ratio is calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports (Table 3-71).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments indicate issues with the ownership of incremental resources. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

85 A unit is classified as base load if it runs for more than 50 percent of hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is between 1000 and 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[86]

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during the first six months of 2020 was unconcentrated (Table 3-71).

Table 3-71 Hourly energy market HHI: January through June, 2019 and 2020[87]

	Hourly Market HHI (Jan - Jun, 2019)	Hourly Market HHI (Jan - Jun, 2020)
Average	792	748
Minimum	599	543
Maximum	1098	1083
Highest market share (One hour)	26%	27%
Average of the highest hourly market share	19%	19%
# Hours	4,343	4,367
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-72 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six months of 2019 and 2020. The PJM energy market was unconcentrated overall with low concentration in the baseload segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

86 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).
87 This analysis includes all hours in the first six months of 2019 and 2020, regardless of congestion.

Table 3-72 Hourly energy market HHI (By supply segment): January through June, 2019 and 2020

	Jan - Jun, 2019			Jan - Jun, 2020		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	675	832	1126	622	791	1138
Intermediate	665	1612	9069	712	1758	9222
Peak	706	6204	10000	647	5619	10000

Figure 3-54 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2020.[88]

Figure 3-54 Fuel source distribution in unit segments: January through June, 2020[89]

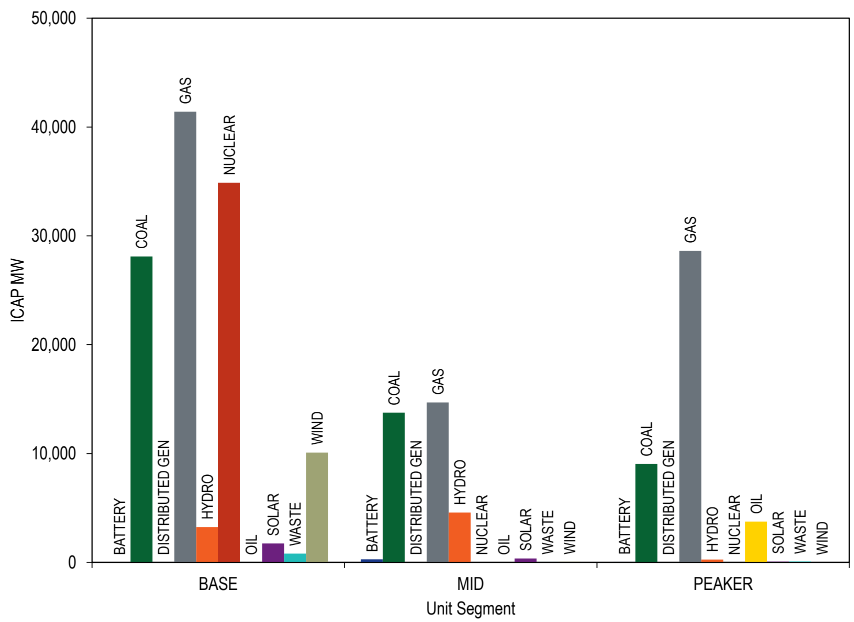
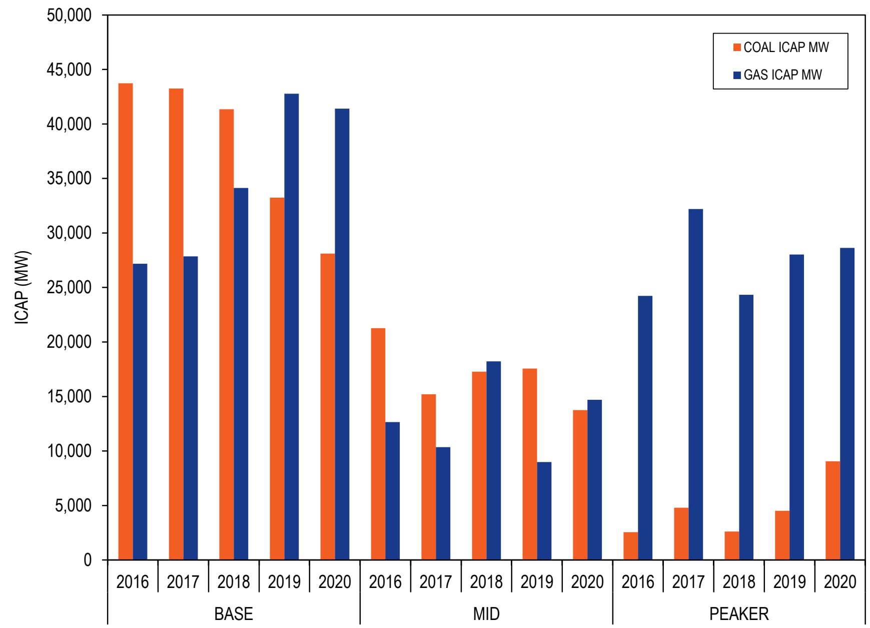


Figure 3-55 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first six months from 2016 through 2020. Figure 3-55 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing, based on operating history for the period from the first six months of 2016 through 2020. In the first six months of 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

Figure 3-55 Unit segment classification by fuel: January through June, 2016 through 2020

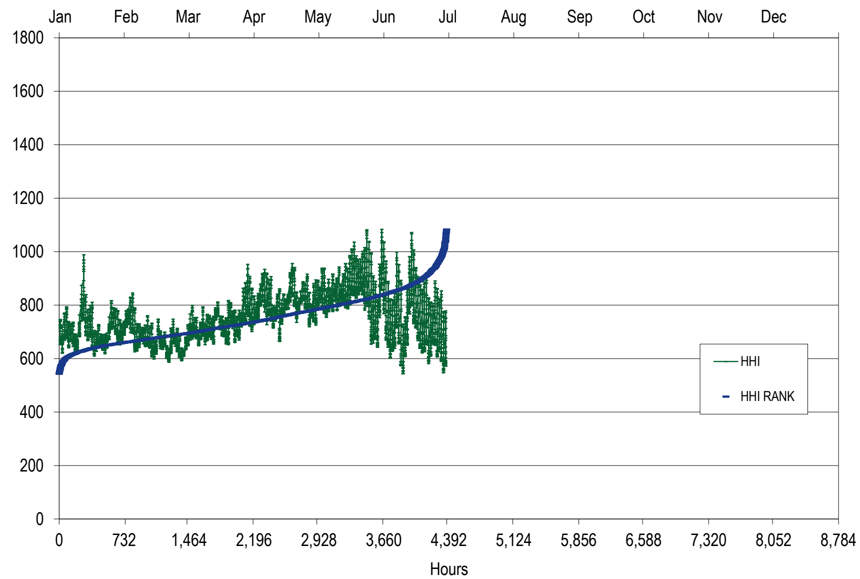


88 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

89 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-56 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2020.

Figure 3-56 Hourly energy market HHI: January through June, 2020



Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[90]

FERC applies tests set forth in the 1996 Merger Policy Statement.[91] FERC is currently reviewing those guidelines.[92]

The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, FERC applies a five step framework, which includes: (1) defining the market; (2) analyze market concentration; (3) analyze mitigative effects of new entry; (4) assess efficiency gains; and (5) assess viability of parties without merger. FERC also applies a Competitive Analysis Screen.[93]

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is contrast to the typical merger filing that uses predefined local markets rather than the actual local markets. The MMU routinely files comments including such analyses.[94] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[95] FERC has considered the MMU's analysis in reviewing mergers.[96]

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-73 shows transactions that involved an entire generation unit or unit owner that were completed in the first six months of 2020, as reported to the Commission.

90 18 U.S.C. § 824b.

91 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

92 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

93 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)

94 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

95 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

96 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

Table 3-73 Completed transfers of entire PJM resources: January through June, 2020

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
FE Coal and Nuclear (Mansfield(retired), Sammis, Eastlake 6, Pleasants, Davis Besse, Perry, Beaver Valley)	FirstEnergy Generation	Avenue Capital (15-20%), Nuveen Asset Management (35 - 40%)	February 27, 2020	EC19-123
Energy Center Dover	Clearway Thermal LLC (Global Infrastructure Management LLC)	DB Energy Assets (DCO Energy and Basalt Infrastructure Partners)	March 2, 2020	EC19-142
Krayn Wind	Krayn Wind LLC	Oppidum Capital, S.L.	March 4, 2020	EC20-26
Beech Ridge Wind	Invenergy	Southern Power	May 1, 2020	EC20-27
Panda Liberty, Panda Patriot	Panda Power Funds	EIG, Carlyle Group	June 17, 2020	EC20-33

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[97] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[98] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the Day-Ahead Energy Market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[99] Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-57 shows the number of days in 2019 and in the first six months of 2020 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the day-ahead energy market. One supplier was singly

97 See 138 FERC ¶ 61,167 at P 19.

98 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

99 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

pivotal on the summer peak day in 2019. Two suppliers were jointly pivotal on 35 days in 2019 and on 24 days in the first six months of 2020. Three suppliers were jointly pivotal on 228 days in 2019 and on 130 days in the first six months of 2020, despite average HHIs at persistently unconcentrated levels. In 2019, the highest levels of aggregate market power occurred in the third quarter, PJM's peak load season. The frequency of pivotal suppliers increased on high demand days in the first week of October 2019, around the Martin Luther King Jr. Day holiday in 2019 and 2020, and on March 1 and 23, 2020. The frequency of pivotal suppliers increased in the first six months of 2020. With low energy prices, there are fewer low cost competitors.

Figure 3-57 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

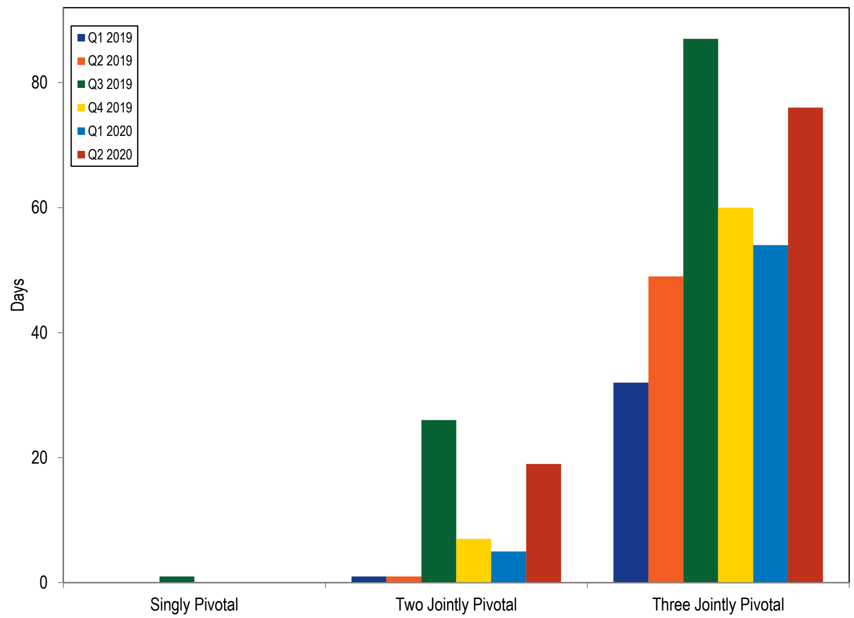


Table 3-74 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first six months of 2020. The first and second pivotal suppliers were jointly pivotal with one another on 13.2 percent of days in the first six months of 2020. All of the top 10 suppliers were one of three pivotal suppliers on at least 64 days in the first six months of 2020.

Table 3-74 Day-ahead market pivotal supplier frequency: January through June, 2020

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	0	0.0%	24	13.2%	130	71.4%
2	0	0.0%	24	13.2%	129	70.9%
3	0	0.0%	19	10.4%	130	71.4%
4	0	0.0%	11	6.0%	81	44.5%
5	0	0.0%	8	4.4%	107	58.8%
6	0	0.0%	2	1.1%	72	39.6%
7	0	0.0%	1	0.5%	63	34.6%
8	0	0.0%	0	0.0%	77	42.3%
9	0	0.0%	0	0.0%	67	36.8%
10	0	0.0%	0	0.0%	64	35.2%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[100] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first six months of 2020, the 500 kV system, the AEP, APS, ATSI, BGE, ComEd, Dominion, Met-Ed, PENELEC, and PPL Control Zones, and MISO experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint (Table 3-75).[101] The Ontario Hydro flowgate is mapped to EXT and it was binding for 53 hours in the first six months of 2020. The AECO, DAY, DEOK, DLCO, DPL, EKPC, JCPL, OVEC, PECO, Pepco, PSEG, and RECO Control Zones did not have constraints binding for 50 or more hours in the first six months of 2020. Table 3-75 shows that the 500 kV system, the AEP and ComEd Control Zones, and MISO experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from January through June, 2009 through 2020. The DAY, OVEC, and RECO Control Zones did not experience congestion resulting from one or more constraints binding for 50 or more hours or resulting from any interface constraint was binding for one or more hours in any year from January through June, 2009 through 2020.

100 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

101 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the Control Zones including AECO, BGE, DPL, JCPK, Met-Ed, PECO, PENELEC, Pepco, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

Table 3-75 Congestion hours resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2020

	(Jan - Jun)											
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
500 kV System	2,026	2,861	2,650	369	720	1,370	722	700	341	458	1,216	1,767
AECO	149	69	88	0	0	0	0	383	0	0	136	0
AEP	932	355	1,409	322	811	1,773	1,902	471	456	1,020	137	739
APS	198	410	52	113	51	170	451	79	0	81	0	333
ATSI	101	0	0	1	70	403	464	0	483	1,866	237	263
BGE	90	154	184	1,556	316	1,142	3,079	4,923	772	1,861	205	2,458
ComEd	576	1,406	153	845	1,678	1,729	1,727	2,910	748	564	283	923
DAY	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	58	0	0	69	0	0	68	0	0
DLCO	156	342	0	209	0	281	747	0	0	57	0	0
Dominion	310	589	659	200	0	52	1,422	759	80	136	0	584
DPL	0	0	0	126	142	560	1,199	1,399	326	295	0	0
EKPC	0	0	0	0	0	65	0	0	0	159	0	0
EXT	0	0	0	0	0	0	0	0	743	0	56	53
JCPL	0	0	0	0	0	0	79	0	0	0	0	0
Met-Ed	0	0	0	68	73	0	182	0	0	1,235	182	564
MISO	3,554	1,879	3,749	7,080	8,549	10,367	6,570	7,191	3,871	4,224	3,058	2,194
NYISO	0	0	0	0	167	121	149	1,374	332	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0
PECO	59	0	130	53	256	944	485	732	852	130	187	0
PENELEC	55	0	0	0	0	1,441	1,385	551	1,537	1,127	1,009	1,940
Pepco	0	0	59	203	85	39	0	0	0	0	0	0
PPL	176	0	52	146	188	147	0	0	741	177	682	836
PSEG	438	479	605	316	1,462	2,023	2,591	220	159	334	248	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	126	0	0	0	0	0	162	0

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first six months of 2020.[102] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times. IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment.

The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-76 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints. Table 3-77 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-76 and Table 3-77 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times.

Table 3-76 Three pivotal supplier test details for interface constraints: January through June, 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	320	599	16	4	12
	Off Peak	125	509	15	8	7
CPL - DOM	Peak	100	266	6	0	6
	Off Peak	85	197	6	0	5
PA Central	Peak	38	347	4	1	4
	Off Peak	64	350	4	0	4

102 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-77 Three pivotal supplier test details for top 10 congested constraints: January through June, 2020

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
PA Central	Peak	38	347	4	1	4
	Off Peak	64	350	4	0	4
Lenox - North Meshoppen	Peak	12	40	2	0	2
	Off Peak	6	33	2	0	2
Prince George	Peak	71	144	12	6	6
	Off Peak	64	138	12	6	6
Paradise - BR Tap	Peak	64	107	1	0	1
	Off Peak	66	110	1	0	1
Nottingham	Peak	24	50	1	0	1
	Off Peak	28	35	1	0	1
Haumesser Road - Steward	Peak	13	48	3	0	3
	Off Peak	15	39	3	0	3
Powerton - Towerline	Peak	29	4	2	0	2
	Off Peak	32	4	2	0	2
Bagley - Graceton	Peak	9	25	1	0	1
	Off Peak	15	25	2	0	2
Vermilion - Tilton Energy Center	Peak	26	15	3	0	3
	Off Peak	21	11	2	0	2
Sub 85 - Rock Island	Peak	51	84	9	2	7
	Off Peak	58	96	10	2	8

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[103] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Table 3-78 and Table 3-79 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the real-time energy market. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint.

103 If a steam unit were to lower its cost-based offer in real-time, it would become eligible for offer capping based on the online TPS test.

Table 3-78 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2020

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AP South	Peak	62	50	81%	0	0%	0%
	Off Peak	6	6	100%	0	0%	0%
CPL - DOM	Peak	2,185	2,151	98%	2	0%	0%
	Off Peak	1,008	1,007	NA	1	NA	NA
PA Central	Peak	14,757	10,097	68%	2	0%	0%
	Off Peak	15,314	10,499	69%	4	0%	0%

Table 3-79 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through June, 2020

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
PA Central	Peak	14,757	10,097	68%	2	0%	0%
	Off Peak	15,314	10,499	69%	4	0%	0%
Lenox - North Meshoppen	Peak	16,231	11,854	73%	0	0%	0%
	Off Peak	11,557	4,622	40%	0	0%	0%
Prince George	Peak	12,764	12,421	97%	50	0%	0%
	Off Peak	7,033	6,921	98%	36	1%	1%
Paradise - BR Tap	Peak	7,193	1,294	18%	0	0%	0%
	Off Peak	5,614	639	11%	0	0%	0%
Nottingham	Peak	6,049	91	2%	0	0%	0%
	Off Peak	4,827	65	1%	0	0%	0%
Haumesser Road - Steward	Peak	3,503	2,187	62%	1	0%	0%
	Off Peak	1,718	874	51%	0	0%	0%
Powerton - Towerline	Peak	2,480	727	29%	2	0%	0%
	Off Peak	1,717	746	43%	0	0%	0%
Bagley - Graceton	Peak	1,306	210	16%	0	0%	0%
	Off Peak	4,434	726	16%	0	0%	0%
Vermilion - Tilton Energy Center	Peak	2,033	616	30%	0	0%	0%
	Off Peak	4,777	747	16%	0	0%	0%
Sub 85 - Rock Island	Peak	4,605	4,509	98%	20	0%	0%
	Off Peak	3,199	3,108	97%	14	0%	0%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. This is consistent with the day-ahead energy market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[104]

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

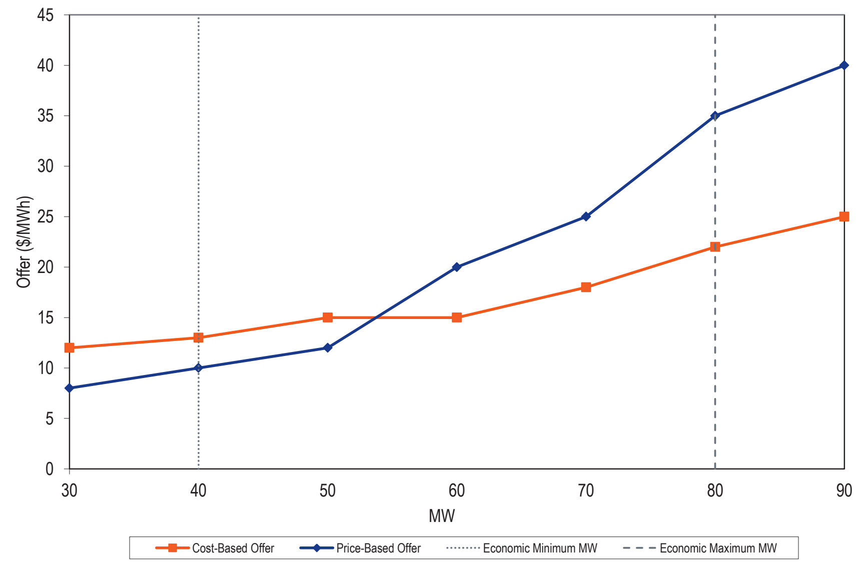
where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-58 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

104 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

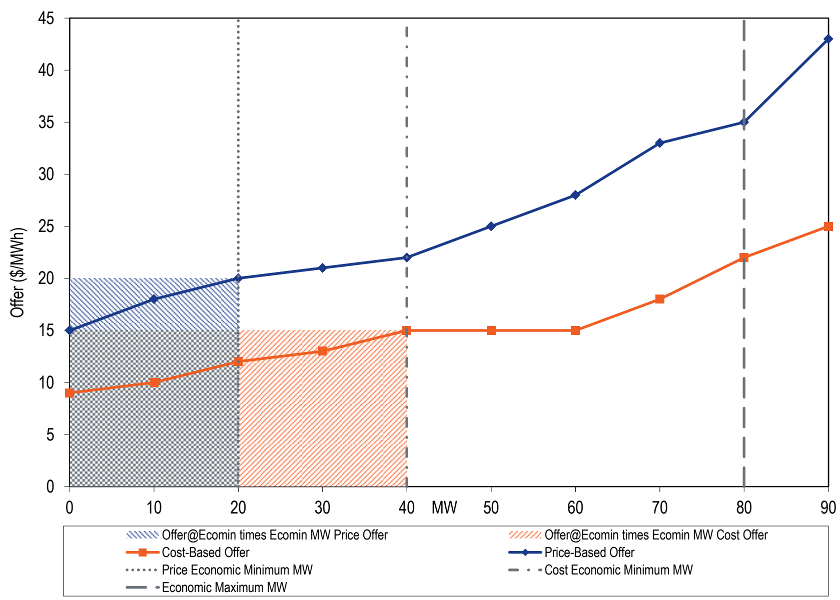
Figure 3-58 Offers with varying markups at different MW output levels



Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup.

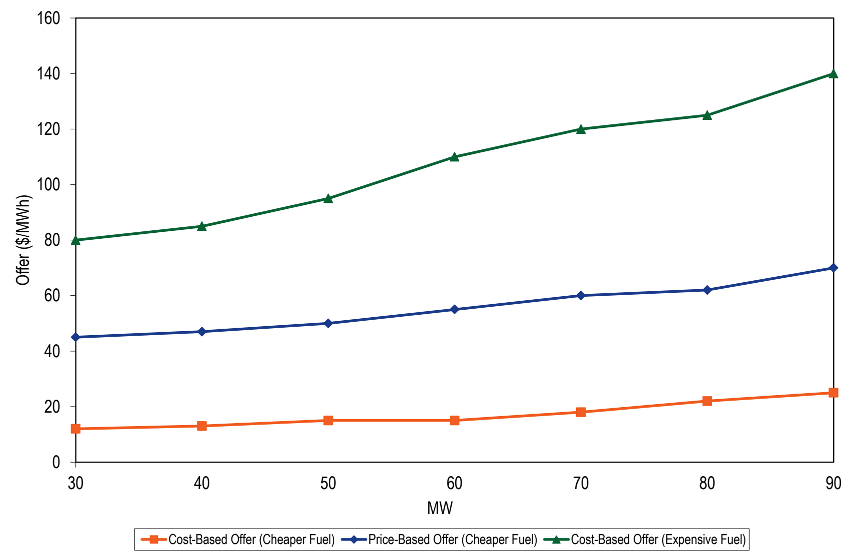
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-59 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-59 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-60 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-60 Dual fuel unit offers



These issues can be solved by simple rule changes.[105] The MMU recommends that markup of price-based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

105 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

Levels of offer capping have historically been low in PJM, as shown in Table 3-81. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[106] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-80 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[107] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the slightly higher rate of offer capping in the real-time energy market in since 2017.

106 See OATT Attachment K Appendix § 6.4.1.

107 Prior to the *2018 Quarterly State of the Market report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-80 Offer capping statistics – energy only: January through June, 2016 to 2020

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.3%	0.2%	0.1%	0.1%
2017	0.2%	0.1%	0.0%	0.0%
2018	1.3%	0.5%	0.1%	0.1%
2019	0.8%	0.7%	0.5%	0.4%
2020	0.9%	1.4%	1.2%	1.2%

Table 3-81 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including units committed to provide reactive support. PJM created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-80.

Table 3-81 Offer capping statistics for energy and reliability: January through June, 2016 to 2020

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.4%	0.2%	0.1%	0.1%
2017	0.3%	0.5%	0.2%	0.4%
2018	1.5%	0.8%	0.2%	0.4%
2019	0.8%	0.7%	0.5%	0.4%
2020	0.9%	1.4%	1.2%	1.2%

Table 3-82 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The data in Table 3-82 is the difference between the offer cap percentages shown in Table 3-81 and Table 3-80.

Table 3-82 Offer capping statistics for reliability: January through June, 2016 to 2020

	Real-Time		Day-Ahead	

(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2016	0.1%	0.0%	0.1%	0.0%
2017	0.1%	0.4%	0.2%	0.4%
2018	0.2%	0.3%	0.1%	0.3%
2019	0.0%	0.0%	0.0%	0.0%
2020	0.0%	0.0%	0.0%	0.0%

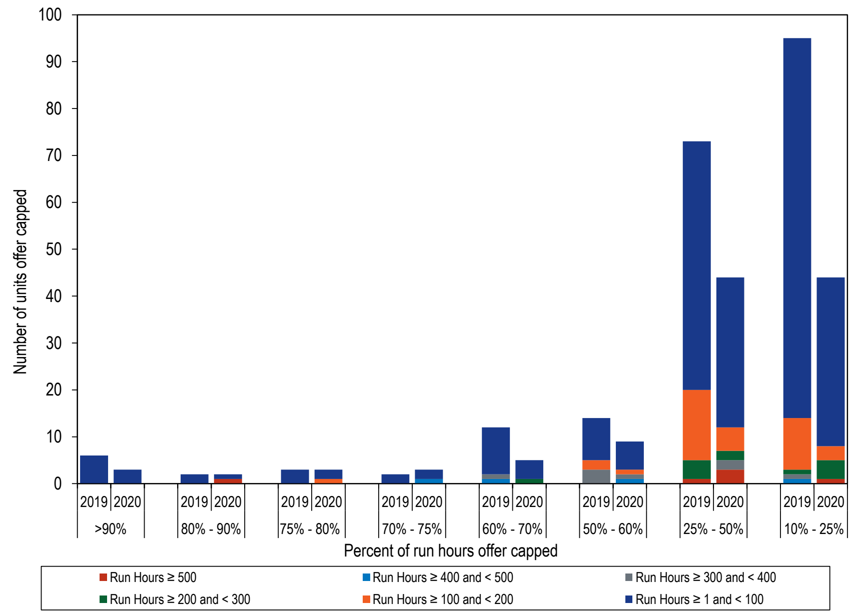
Table 3-83 presents data on the frequency with which units were offer capped in the first six months of 2019 and 2020 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-83 shows that three units were offer capped for 90 percent or more of their run hours in the first six months of 2020 compared to six units in the first six months of 2019.

Table 3-83 Real-time offer capped unit statistics: January through June, 2019 and 2020

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Jun	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2019	0	0	0	0	0	6
90%	2020	0	0	0	0	0	3
	2019	0	0	0	0	0	2
80% and < 90%	2020	1	0	0	0	0	1
	2019	0	0	0	0	0	3
75% and < 80%	2020	0	0	0	0	1	2
	2019	0	0	0	0	0	2
70% and < 75%	2020	0	1	0	0	0	2
	2019	0	1	1	0	0	10
60% and < 70%	2020	0	0	0	1	0	4
	2019	0	0	3	0	2	9
50% and < 60%	2020	0	1	1	0	1	6
	2019	1	0	0	4	15	53
25% and < 50%	2020	3	0	2	2	5	32
	2019	0	1	1	1	11	81
10% and < 25%	2020	1	0	0	4	3	36

Figure 3-61 shows the frequency with which units were offer capped in the first six months of 2019 and 2020 for failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons.

Figure 3-61 Real-time offer capped unit statistics: January through June, 2019 and 2020



Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[108] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

108 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Real-Time Markup Index

Table 3-84 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-85 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[109] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. While the 10 percent adder is permitted under the definition of cost-based offers in the PJM Market Rules and some have interpreted the rules to permit maintenance costs that are not short run marginal costs, neither are part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflects that fact.[110]

109 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

110 See PJM. "Manual 15: Cost Development Guidelines," Rev. 35 (April 24, 2020).

In the first six months of 2020, 99.5 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $10 was negative (-$1.15 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.43 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first six months of 2020, none had offer prices above $400 per MWh. Among the units that were marginal in the first six months of 2019, less than one percent had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first six months of 2020 was more than $150, while the highest markup in the first six months of 2019 was more than $350.

Table 3-84 Average, real-time marginal unit markup index (By offer price category unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.25	($3.10)	3.9%	(0.02)	($1.15)	13.3%
$10 to $15	(0.05)	($0.95)	5.2%	0.04	$0.43	45.0%
$15 to $20	0.07	$1.14	32.4%	0.02	($0.12)	30.9%
$20 to $25	0.03	$0.33	35.1%	0.04	$0.63	8.4%
$25 to $50	0.07	$1.84	20.8%	0.18	$5.96	1.9%
$50 to $75	0.31	$17.95	1.1%	0.54	$31.85	0.2%
$75 to $100	0.46	$39.92	0.4%	0.68	$60.37	0.1%
$100 to $125	0.29	$31.21	0.4%	0.77	$87.54	0.0%
$125 to $150	0.34	$46.74	0.1%	0.32	$41.51	0.0%
$150 to $400	0.08	$16.87	0.5%	0.53	$90.42	0.1%
>= $400	0.10	$45.99	0.0%	0.00	$0.00	0.0%

Table 3-85 Average, real-time marginal unit markup index (By offer price category adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency

< $10	0.25	($3.04)	3.9%	0.03	($0.66)	13.3%
$10 to $15	0.04	$0.41	5.2%	0.13	$1.56	45.0%
$15 to $20	0.15	$2.68	32.4%	0.10	$1.46	30.9%
$20 to $25	0.11	$2.33	35.1%	0.12	$2.54	8.4%
$25 to $50	0.15	$4.40	20.8%	0.25	$8.20	1.9%
$50 to $75	0.37	$21.55	1.1%	0.58	$34.24	0.2%
$75 to $100	0.51	$43.98	0.4%	0.71	$62.92	0.1%
$100 to $125	0.36	$38.15	0.4%	0.79	$89.93	0.0%
$125 to $150	0.40	$54.79	0.1%	0.39	$49.81	0.0%
$150 to $400	0.17	$32.02	0.5%	0.58	$97.56	0.1%
>= $400	0.20	$84.46	0.0%	0.00	$0.00	0.0%

Table 3-86 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[111] Table 3-87 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first six months of 2020, using unadjusted cost-based offers for coal units, 58.86 percent of marginal coal units had negative markups. In the first six months of 2020, using adjusted cost-based offers for coal units, 36.32 percent of marginal coal units had negative markups.

Table 3-86 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	50.96%	22.01%	27.02%	58.86%	23.66%	17.47%
Gas	30.15%	13.89%	55.96%	32.49%	3.90%	63.61%
Oil	1.92%	96.15%	1.92%	0.00%	100.00%	0.00%

Table 3-87 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	35.22%	16.73%	48.05%	36.32%	17.42%	46.25%
Gas	10.28%	6.04%	83.69%	20.33%	2.68%	77.00%
Oil	0.77%	96.15%	3.08%	0.00%	84.62%	15.38%

111 Other fuel types were excluded based on data confidentiality rules.

Figure 3-62 shows the frequency distribution of hourly markups for all gas units offered in the first six months of 2019 and 2020 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[112] Of the gas units offered in the PJM market in the first six months of 2020, 23.7 percent of gas unit-hours had a maximum markup that was negative. More than 9.0 percent of gas fired unit-hours had a maximum markup above $100 per MWh. The number of gas units with markups from $200 to $1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

112 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-62 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through June, 2019 and 2020

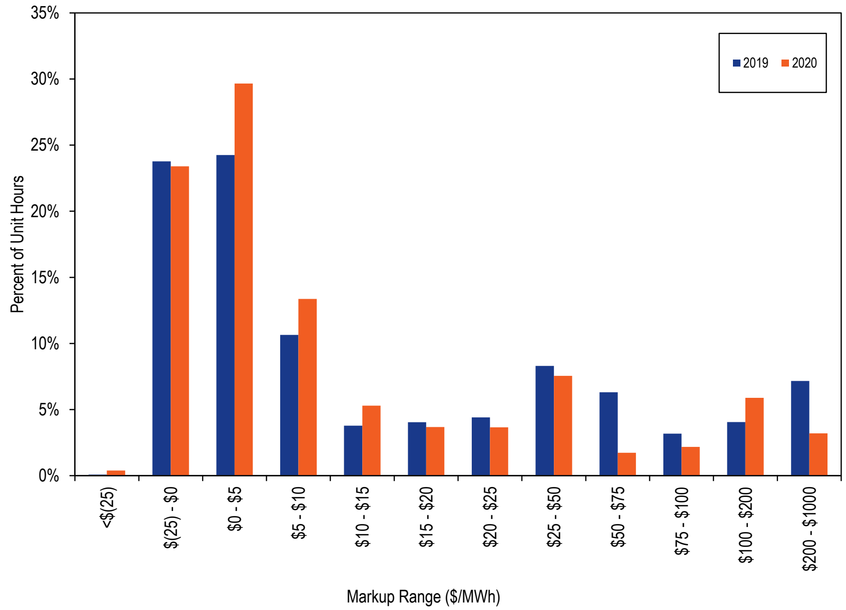


Figure 3-63 shows the frequency distribution of hourly markups for all coal units offered in the first six months of 2019 and 2020 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first six months of 2020, 48.5 percent of coal unit-hours had a maximum markup that was negative or equal to zero, increasing from 36.7 in the first six months of 2019.

Figure 3-63 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through June, 2019 and 2020

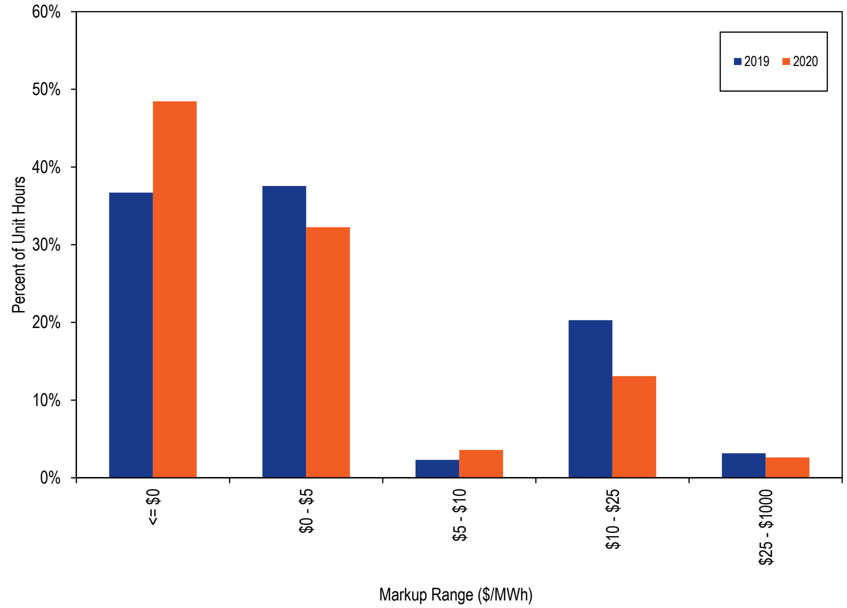


Figure 3-64 shows the frequency distribution of hourly markups for all offered oil units in the first six months of 2019 and 2020 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first six months of 2020, 39.9 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 6.6 percent of oil fired unit-hours had a maximum markup above $100 per MWh. The number of oil units with markups from $100 to $1,000 per MWh decreased due to increases in the maintenance costs allowable in cost-based offers, not a decrease in the offer level and not a decrease in the markups.

Figure 3-64 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through June, 2019 and 2020

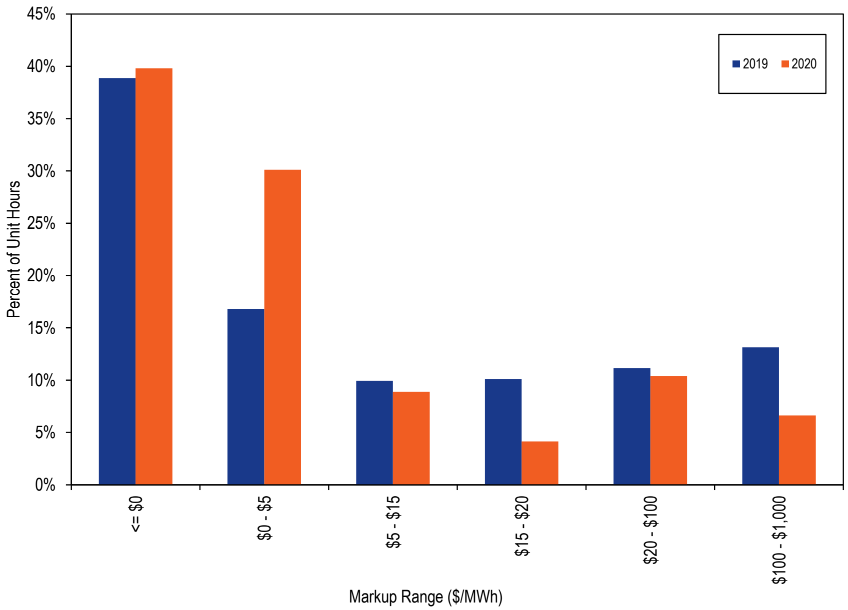
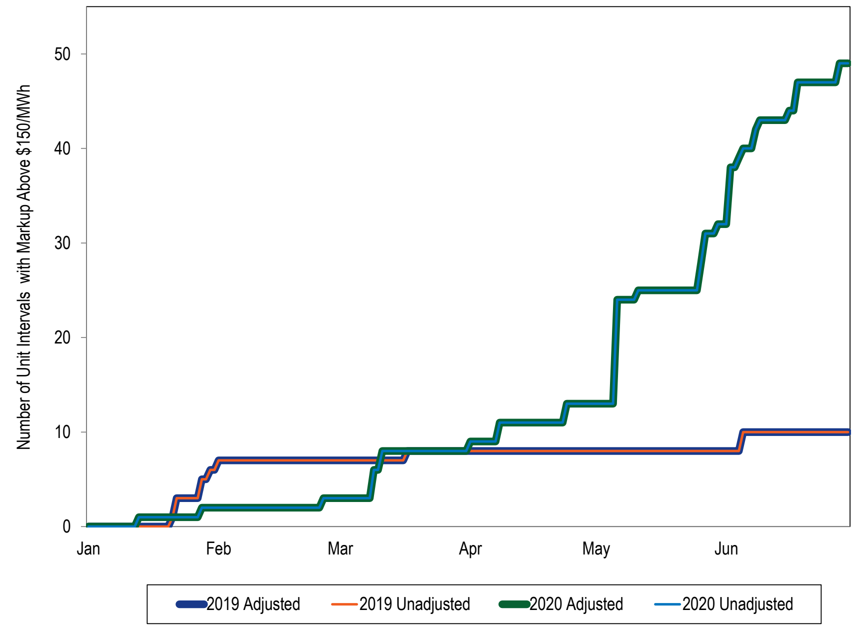


Figure 3-65 Cumulative number of unit intervals with markups above $150 per MWh: January through June, 2019 and 2020



The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-65 shows the number of marginal unit intervals in the first six months of 2020 and 2019 with markup above $150 per MWh.

Day-Ahead Markup Index

Table 3-88 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. In the first six months of 2020, 97.7 percent of marginal generating units had offer prices less than $25 per MWh. The average dollar markups of units with offer prices less than $10 was negative (-$0.71 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was positive ($0.96 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in the first six months of 2019 and

2020, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first six months of 2020 was about $80 per MWh while the highest markup in the first six months of 2019 was about $90 per MWh.

Table 3-88 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	1.14	$3.34	1.5%	0.01	($0.71)	8.7%
$10 to $15	(0.04)	($0.76)	2.6%	0.09	$0.96	36.8%
$15 to $20	0.06	$1.01	26.1%	0.15	$2.03	41.1%
$20 to $25	0.03	$0.49	37.5%	0.01	($0.29)	11.2%
$25 to $50	0.05	$1.57	30.8%	0.03	$0.58	2.2%
$50 to $75	0.17	$9.52	0.9%	0.00	$0.00	0.0%
$75 to $100	0.30	$27.58	0.1%	0.51	$47.56	0.0%
$100 to $125	0.48	$49.48	0.1%	(0.05)	($6.24)	0.0%
$125 to $150	0.32	$45.31	0.2%	0.00	$0.00	0.1%
>= $150	0.20	$34.53	0.2%	0.15	$25.35	0.0%

Table 3-89 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In the first six months of 2020, 41.1 percent of marginal generating units had offers between $15 and $20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index decreased from 1.14 in the first six months of 2019, to 0.08 in the first six months of 2020 in the offer price category less than $10.

Table 3-89 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	1.14	$3.34	1.5%	0.08	($0.26)	8.7%
$10 to $15	0.05	$0.57	2.6%	0.16	$2.05	36.8%
$15 to $20	0.15	$2.56	26.1%	0.22	$3.41	41.1%
$20 to $25	0.12	$2.48	37.5%	0.09	$1.73	11.2%
$25 to $50	0.13	$4.10	30.8%	0.11	$3.10	2.2%
$50 to $75	0.24	$13.82	0.9%	0.00	$0.00	0.0%
$75 to $100	0.36	$33.15	0.1%	0.52	$48.18	0.0%
$100 to $125	0.53	$54.38	0.1%	0.04	$5.11	0.0%
$125 to $150	0.38	$53.81	0.2%	0.09	$12.16	0.1%
>= $150	0.24	$42.28	0.2%	0.15	$25.35	0.0%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first six months of 2020, 6.7 percent of the marginal units set prices based on cost-based offers, 2.0 percentage points less than the first six months of 2019.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer is that the cost is "directly related to electric production."[113]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[114]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

The MMU recommends that PJM require that the level of costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-90 shows the status of all Fuel Cost Policies as of June 30, 2020. As of June 30, 2020, 1,208 units (92 percent) had an FCP passed by the MMU, zero units had an FCP under the MMU review (submitted) and 98 units (8 percent) had an FCP failed by the MMU. The number of units with fuel cost policies failed by the MMU included units with 16,739 MW. All units had an FCP approved by PJM. The proportion of units with fuel cost policies passed by the MMU remained constant at 92 percent in the 2019 Annual Fuel Cost Policy Review and as of June 30, 2020.

113 See 167 FERC ¶ 61,030 (2019).

114 See OA Schedule 2(a).

Table 3-90 FCP Status for PJM Generating Units: June 30, 2020

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	1,208	0	98	1,306
Revoked	0	0	0	0
Expired	0	0	0	0
Total	1,208	0	98	1,306

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic:[115] Verifiable means that the FCP must provide that a market seller provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a standardized method or methods for calculating fuel costs including objective triggers for each method.[116] PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[117] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[118]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

115 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
116 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
117 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
118 September 16th Filing at P 8.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some Fuel Cost Policies did not meet are:[119] accuracy (reflect applicable costs accurately); procurement practices (provide information sufficient for the verification of the market seller's fuel procurement practices where relevant); fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in $ per MWh or in $ per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar resources.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were:

- Unverifiable cost estimates. Some of these policies include options under which the estimate of the natural gas commodity cost would be calculated by the market seller without specifying a verifiable, objective, quantitative method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.
- Use of available market information that results in inaccurate expected costs. Some market sellers include the use of offers to sell natural gas

119 See PJM Operating Agreement Schedule 2 § 2.3 (a).

on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved inaccurate Fuel Cost Policies.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. In a large number of approved Fuel Cost Policies, the actual fuel procurement process plays no role in calculating the Market Seller's accurate estimate of the daily replacement value of their fuel.

The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with nonzero cost-based offers. PJM should set to zero the cost-based offers of units without an approved Fuel Cost Policy.

Cost-Based Offer Penalties

In addition to implementing the Fuel Cost Policy approval process, the February 3, 2017, FERC order created a process for penalizing generators identified by PJM or the MMU with cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[120] Penalties became effective May 15, 2017.

120 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

In the first six months of 2020, 90 penalty cases were identified, 78 resulted in assessed cost-based offer penalties, two resulted in disagreement between the MMU and PJM, and 10 remain pending PJM's determination. These cases were from 79 units owned by 14 different companies. Table 3-92 shows the penalties by the year in which participants were notified.

Table 3-91 Cost-based offer penalty cases by year notified: May 2017 through June 2020

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	187	161	26	0	138	35
2019	58	57	0	1	58	19
2020	90	78	2	10	79	14
Total	392	352	29	11	286	53

Since 2017, 392 penalty cases have been identified, 352 resulted in assessed cost-based offer penalties, 29 resulted in disagreement between the MMU and PJM, and 11 remain pending PJM's determination. The 352 cases were from 286 units owned by 53 different companies. The total penalties were $2.5 million, charged to units that totaled 72,237 available MW. The average penalty was $1.59 per available MW. This means that a 100 MW unit would have paid a penalty of $3,804.[121] Table 3-92 shows the total cost-based offer penalties since 2017 by year.

Table 3-92 Cost-based offer penalties by year: May 2017 through June 2020

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	127	34	$1,265,698	26,343	$2.27
2019	73	19	$489,164	19,732	$1.10
2020	71	10	$191,672	9,232	$0.87
Total	363	54	$2,503,361	72,237	$1.59

121 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved Fuel Cost Policies, Fuel Cost Policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[122] The changes proposed by PJM attempted to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[123] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[124] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory. The purpose of cost-based energy offers is to prevent the exercise of market power in the PJM energy market. PJM administers market power mitigation in the energy market by replacing a generator's market-based offer with its cost-based offer when the generator owner fails the structural test for local market power, the Three Pivotal Supplier ("TPS") test, or is required for reliability. The effectiveness of market power mitigation in delivering competitive market outcomes is based entirely on cost-based offers as the measure of the competitive offer level.

122 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
123 167 FERC ¶ 61,030.
124 168 FERC ¶ 61,134.

When market power is not mitigated, energy prices exceed the competitive level, uplift payments exceed the efficient level, and economic withholding allows generators to collect capacity payments without running, while raising prices for other generators and for load. The competitive offer level is the short run marginal cost of the generator for the relevant market hour.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2018 and 2019.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2019 was 43 percent higher than the approved variable operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls.[125]

The average variable operating and maintenance cost approved by PJM for combined cycles for 2019 was 19 percent higher than the approved variable

125 PJM reviews VOM once per year. The results reflect PJM's most recent review.

operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls.

The average variable operating and maintenance cost approved by PJM for coal units for 2019 was 37 percent higher than the approved variable operating and maintenance cost approved by PJM in 2018. The increase reflects PJM's implementation of the new rules that allow major maintenance and overhauls and the inclusion of other fuel related costs such as fuel handling, chemicals and ash disposal that previously were not part of variable operating and maintenance costs and were part of total fuel related costs.

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

MMU analysis shows that as a unit runs more, the VOM cost as approved by PJM, decreases. This is the result for CTs, CCs and coal plants. This is an indication that fixed costs are being included in VOM costs. By comparison, fuel costs per MWh remain constant or increase as run hours and the heat rate increase. Fixed costs should not be includable in cost-based energy offers.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[126]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy

126 The peak adder is equal to $300 times three divided by 5 MW.

market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Sections 12.3-12.6 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations. The solution algorithm described in Sections 12.5-12.6 is flawed, most notably in its incomplete estimate of a generator's optimal revenue and the algorithm's inability to simultaneously impose multiple environmental or operational constraints typically associated with permits that have rolling limits.

The MMU Opportunity Cost Calculator, described in Manual 15, Section 12.7, is a constrained optimization software application that uses an integer programming solver to find the optimal commitment, dispatch, and lost opportunity cost for a generator based on forward power prices and fuel costs. The MMU calculator incorporates start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations. The MMU recommends that the PJM Opportunity Cost Calculator, which adheres to the solution method described in Sections 12.5-12.6, be discontinued and that the MMU Opportunity Cost Calculator be used for all opportunity cost calculations.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[127] One unit qualified for an FMU adder for the months of September and October, 2019, and two units qualified for an FMU adder in June 2020.

Effective in planning year 2020/2021, default Avoidable Cost Rates will no longer be defined. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit will not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-93 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[128] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first six months of 2020, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first six months of 2020, the offers of one company resulted in 16.2 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 47.2 percent of the real-time, load-weighted, average PJM system LMP. In the first six months of 2020, the offers of one company resulted in 17.3 percent of the peak hour real-time, load-weighted PJM system LMP.

Table 3-93 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through June, 2019 and 2020

2019 (Jan - Jun)						2020 (Jan - Jun)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	12.8%	12.8%	1	13.7%	13.7%	1	16.2%	16.2%	1	17.3%	17.3%
2	10.0%	22.8%	2	10.4%	24.1%	2	12.4%	28.6%	2	14.8%	32.2%
3	9.3%	32.1%	3	8.8%	32.9%	3	10.7%	39.3%	3	10.2%	42.4%
4	9.3%	41.5%	4	7.2%	40.1%	4	7.8%	47.2%	4	7.4%	49.8%
5	4.8%	46.3%	5	5.1%	45.2%	5	5.9%	53.0%	5	5.6%	55.4%
6	4.5%	50.8%	6	4.1%	49.3%	6	5.7%	58.7%	6	4.7%	60.2%
7	4.4%	55.3%	7	4.1%	53.4%	7	4.9%	63.7%	7	4.2%	64.4%
8	3.6%	58.9%	8	3.9%	57.2%	8	3.7%	67.4%	8	3.6%	68.0%
9	3.6%	62.5%	9	3.9%	61.1%	9	3.4%	70.8%	9	2.8%	70.8%
Other (74 companies)	37.5%	100.0%	Other (70 companies)	38.9%	100.0%	Other (67 companies)	29.2%	100.0%	Other (60 companies)	29.2%	100.0%

127 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).
128 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Figure 3-66 shows the first six month marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2012.

Figure 3-66 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through June, 2012 through 2020

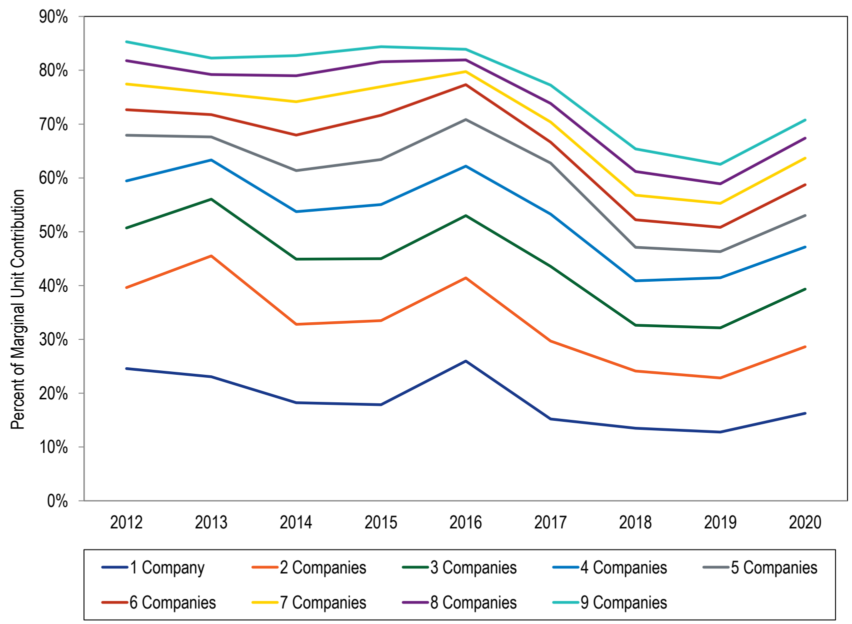


Table 3-94 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[129] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first six months of 2020, the offers of one company contributed 13.3 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 41.2 percent of the day-ahead, load-weighted, average, PJM system LMP.

129 Id.

Table 3-94 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through June, 2019 and 2020

2019 (Jan - Jun)						2020 (Jan - Jun)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	9.4%	9.4%	1	10.7%	10.7%	1	13.3%	13.3%	1	17.7%	17.7%
2	8.3%	17.8%	2	6.9%	6.9%	2	11.7%	25.0%	2	13.7%	31.4%
3	7.0%	24.8%	3	6.5%	6.5%	3	10.5%	35.5%	3	13.5%	44.8%
4	4.7%	29.5%	4	5.0%	5.0%	4	5.6%	41.2%	4	5.3%	50.2%
5	4.6%	34.2%	5	4.2%	4.2%	5	4.9%	46.1%	5	4.8%	54.9%
6	3.8%	37.9%	6	3.9%	3.9%	6	4.5%	50.6%	6	4.2%	59.2%
7	3.7%	41.6%	7	3.7%	3.7%	7	4.1%	54.8%	7	3.9%	63.1%
8	3.3%	45.0%	8	3.4%	3.4%	8	3.6%	58.3%	8	3.4%	66.5%
9	3.0%	47.9%	9	3.2%	3.2%	9	3.2%	61.5%	9	3.4%	70.0%
Other (136 companies)	52.1%	100.0%	Other (126 companies)	52.5%	52.5%	Other (130 companies)	38.5%	100.0%	Other (125 companies)	30.0%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[130] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units,

130 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-95 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $3.86 per MWh in the first six months of 2019 to $1.93 per MWh in the first six months of 2020. The adjusted markup contribution of coal units in the first six months of 2020 was $0.14 per MWh. The adjusted markup component of gas fired units in the first six months of 2020 was $1.80 per MWh, a decrease of $1.13 per MWh from the first six months of 2019. The markup component of wind units was less than $0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first six months of 2020, among the wind units that were marginal, 91.8 percent had negative offer prices.

Table 3-95 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2019 and 2020[131]

		2019 (Jan - Jun)		2020 (Jan - Jun)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.09	$0.93	($0.51)	$0.14
Gas	CC	$1.57	$2.72	$0.82	$1.65
Gas	CT	$0.05	$0.16	$0.10	$0.17
Gas	RICE	$0.03	$0.04	$0.05	$0.05
Gas	Steam	($0.02)	$0.00	($0.10)	($0.07)
Landfill Gas	CT	($0.00)	($0.00)	$0.00	$0.00
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Oil	CC	($0.00)	$0.00	$0.00	$0.00
Oil	CT	$0.01	$0.01	$0.00	$0.00
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.00)	$0.00	($0.01)	($0.01)
Other	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.00)	($0.00)	($0.01)	($0.01)
Total		$1.71	$3.86	$0.34	$1.93

Markup Component of Real-Time Price

Table 3-96 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-97 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first six months of 2020, when using unadjusted cost-based offers, $0.34 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $1.93 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first six months of 2020, the peak markup component was highest in June, $2.02 per MWh using unadjusted cost-based offers and peak markup component was highest in June, $3.75 per MWh using adjusted cost-based offers. This corresponds to 8.2 percent and 15.2 percent of the real-time peak load-weighted average LMP in June.

Table 3-96 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2019 through June, 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.89	$2.43	$1.33	$0.49	$0.94	$0.03
Feb	$2.15	$2.85	$1.46	($0.15)	($0.00)	($0.28)
Mar	$2.11	$2.57	$1.67	($0.09)	$0.46	($0.66)
Apr	$1.38	$2.01	$0.67	($0.07)	$0.17	($0.33)
May	$1.27	$2.02	$0.45	$0.54	$1.03	$0.10
Jun	$1.36	$1.74	$0.98	$1.24	$2.02	$0.30
Jul	$3.25	$4.40	$1.99			
Aug	$0.86	$0.78	$0.95			
Sep	$1.57	$2.58	$0.55			
Oct	$1.39	$2.01	$0.64			
Nov	$1.12	$1.79	$0.51			
Dec	$0.19	$0.29	$0.08			
Total	$1.58	$2.16	$0.97	$0.34	$0.81	($0.14)

131 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-97 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June, 2019 and 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$4.45	$5.21	$3.65	$2.21	$2.80	$1.60
Feb	$4.33	$5.11	$3.55	$1.57	$1.85	$1.30
Mar	$4.37	$4.93	$3.84	$1.44	$2.07	$0.81
Apr	$3.40	$4.16	$2.53	$1.43	$1.73	$1.11
May	$3.23	$4.15	$2.22	$1.98	$2.65	$1.39
Jun	$3.21	$3.79	$2.64	$2.77	$3.75	$1.58
Jul	$5.38	$6.71	$3.92			
Aug	$2.81	$3.03	$2.55			
Sep	$3.61	$4.85	$2.36			
Oct	$3.17	$4.00	$2.17			
Nov	$3.18	$3.95	$2.49			
Dec	$2.12	$2.38	$1.88			
Total	$3.64	$4.40	$2.86	$1.93	$2.53	$1.31

Hourly Markup Component of Real-Time Prices

Figure 3-67 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2019 and the first six months of 2020. Figure 3-68 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2019 and the first six months of 2020.

Figure 3-67 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2019 and 2020

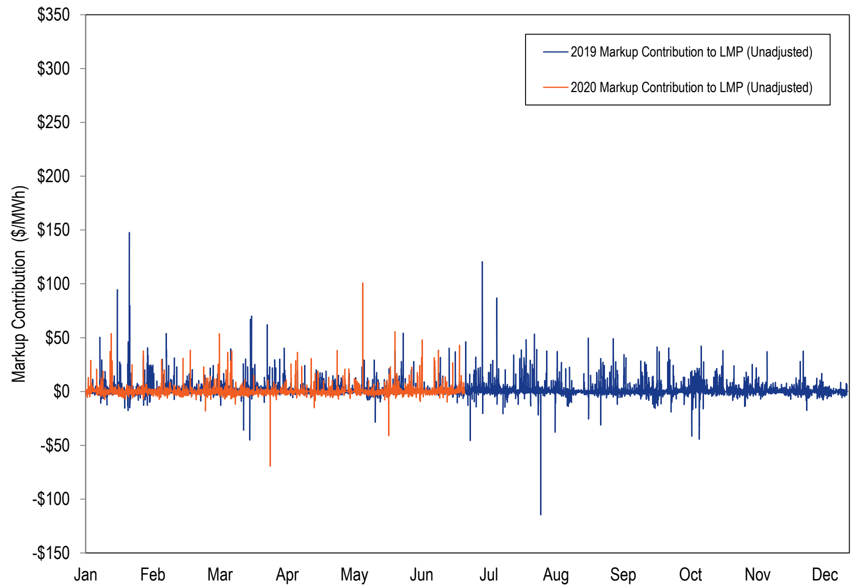


Figure 3-68 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2019 and 2020

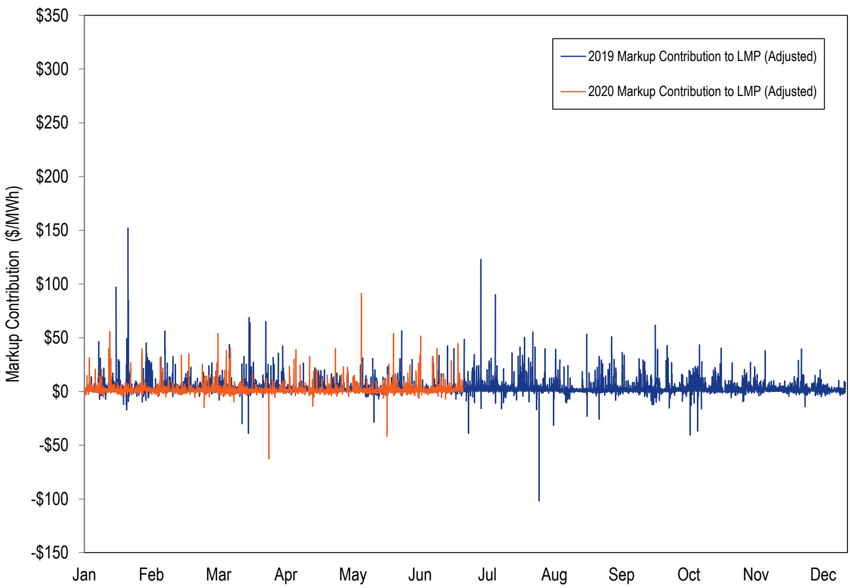


Table 3-98 Average real-time zonal markup component (Unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.29	$2.90	$1.70	$0.29	$0.68	($0.10)
AEP	$1.54	$2.06	$1.01	$0.35	$0.81	($0.12)
APS	$1.59	$2.09	$1.08	$0.40	$0.93	($0.13)
ATSI	$1.61	$2.11	$1.08	$0.41	$0.87	($0.08)
BGE	$1.52	$2.09	$0.94	$0.59	$1.28	($0.10)
ComEd	$1.40	$2.22	$0.53	$0.28	$0.81	($0.29)
DAY	$1.61	$2.16	$1.01	$0.41	$0.88	($0.09)
DEOK	$1.46	$1.99	$0.93	$0.38	$0.87	($0.13)
DLCO	$1.57	$2.07	$1.05	$0.48	$1.04	($0.10)
Dominion	$1.56	$2.08	$1.03	$0.38	$0.89	($0.14)
DPL	$2.46	$2.88	$2.03	$0.22	$0.62	($0.19)
EKPC	$1.45	$1.96	$0.95	$0.33	$0.85	($0.17)
JCPL	$2.29	$2.84	$1.70	$0.28	$0.62	($0.09)
Met-Ed	$1.94	$2.44	$1.41	$0.25	$0.60	($0.12)
OVEC	$1.34	$1.88	$0.85	$0.17	$0.62	($0.23)
PECO	$2.26	$2.77	$1.72	$0.23	$0.62	($0.17)
PENELEC	$1.72	$2.16	$1.26	$0.32	$0.70	($0.09)
Pepco	$1.55	$2.07	$1.01	$0.48	$1.07	($0.12)
PPL	$2.16	$2.71	$1.59	$0.23	$0.45	$0.01
PSEG	$2.39	$3.05	$1.69	$0.25	$0.62	($0.13)
RECO	$2.13	$2.72	$1.47	$0.21	$0.53	($0.14)

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first six months of 2019 and 2020 in Table 3-98 and for adjusted offers in Table 3-99[132]. The smallest zonal all hours average markup component using unadjusted offers in the first six months of 2020, was in the OVEC Control Zone, $0.17 per MWh, while the highest was in the BGE Control Zone, $0.59 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first six months of 2020, was in the PPL Control Zone, $0.45 per MWh, while the highest was in the BGE Control Zone, $1.28 per MWh.

132 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-99 Average real-time zonal markup component (Adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$4.31	$5.03	$3.60	$1.80	$2.30	$1.31
AEP	$3.71	$4.40	$3.02	$1.96	$2.57	$1.35
APS	$3.79	$4.46	$3.12	$2.02	$2.68	$1.34
ATSI	$3.80	$4.48	$3.10	$2.03	$2.65	$1.39
BGE	$3.89	$4.64	$3.13	$2.29	$3.13	$1.45
ComEd	$3.40	$4.38	$2.37	$1.76	$2.47	$1.01
DAY	$3.86	$4.59	$3.08	$2.10	$2.71	$1.44
DEOK	$3.63	$4.31	$2.92	$1.99	$2.62	$1.35
DLCO	$3.72	$4.39	$3.03	$2.09	$2.81	$1.35
Dominion	$3.84	$4.53	$3.14	$2.01	$2.67	$1.36
DPL	$4.55	$5.07	$4.02	$1.76	$2.24	$1.28
EKPC	$3.64	$4.29	$3.00	$1.95	$2.59	$1.33
JCPL	$4.35	$5.02	$3.63	$1.81	$2.27	$1.34
Met-Ed	$4.04	$4.68	$3.35	$1.80	$2.25	$1.32
OVEC	$3.43	$4.14	$2.80	$1.74	$2.34	$1.21
PECO	$4.28	$4.91	$3.62	$1.73	$2.21	$1.24
PENELEC	$3.83	$4.41	$3.21	$1.85	$2.35	$1.32
Pepco	$3.87	$4.56	$3.15	$2.14	$2.86	$1.40
PPL	$4.19	$4.87	$3.47	$1.71	$2.01	$1.39
PSEG	$4.43	$5.21	$3.62	$1.78	$2.26	$1.29
RECO	$4.08	$4.76	$3.32	$1.74	$2.17	$1.26

Markup by Real-Time Price Levels

Table 3-100 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-100 Real-time markup contribution (By PJM load-weighted LMP category, unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($3.08)	0.5%	($0.99)	2.6%
$10 to $15	($0.40)	3.1%	($0.43)	25.9%
$15 to $20	$0.18	18.5%	($0.85)	43.9%
$20 to $25	$0.05	37.5%	$0.56	18.5%
$25 to $50	$2.52	37.1%	$5.53	7.8%
$50 to $75	$13.21	2.1%	$15.10	1.0%
$75 to $100	$24.48	0.7%	$11.73	0.2%
$100 to $125	$19.62	0.2%	$12.51	0.0%
$125 to $150	$33.06	0.1%	$2.41	0.0%
>= $150	$6.42	0.2%	$5.71	0.0%

Table 3-101 Real-time markup contribution (By PJM load-weighted LMP category, adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($2.18)	0.5%	($0.09)	2.6%
$10 to $15	$0.91	3.1%	$0.79	25.8%
$15 to $20	$1.82	18.5%	$0.79	43.9%
$20 to $25	$2.08	37.5%	$2.42	18.6%
$25 to $50	$4.93	37.1%	$7.44	7.8%
$50 to $75	$16.44	2.1%	$17.22	1.0%
$75 to $100	$28.41	0.7%	$13.03	0.2%
$100 to $125	$24.83	0.2%	$14.18	0.0%
$125 to $150	$37.12	0.1%	$6.36	0.0%
>= $150	$8.97	0.2%	$7.23	0.0%

Markup by Company

Table 3-102 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first six months of 2020, when using unadjusted cost-based offers, the markup of one company accounted for 2.0 percent of the load-weighted average LMP, the markup of the top five companies accounted for 4.3 percent of the load-weighted average LMP and the markup of all companies accounted for 1.8 percent of the load-weighted average LMP. The top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup decreased in the first six months of 2020. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also decreased in the first six months of 2020. The markup contribution of a unit to the real-time, load-weighted average LMP can be positive or negative.

Table 3-102 Markup component of real-time, load-weighted, average LMP by Company: January through June, 2019 and 2020

	2019 (Jan - Jun)				2020 (Jan - Jun)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.47	1.7%	$0.53	1.9%	$0.39	2.0%	$0.62	3.2%
Top 2 Companies	$0.71	2.6%	$1.04	3.8%	$0.53	2.7%	$0.84	4.3%
Top 3 Companies	$0.94	3.4%	$1.52	5.5%	$0.66	3.4%	$1.01	5.2%
Top 4 Companies	$1.13	4.1%	$1.92	7.0%	$0.75	3.9%	$1.18	6.1%
Top 5 Companies	$1.30	4.7%	$2.25	8.2%	$0.83	4.3%	$1.33	6.8%
All Companies	$1.71	6.2%	$3.86	14.1%	$0.34	1.8%	$1.93	9.9%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-103. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 52.3 percent of marginal resources, INCs were 14.3 percent of marginal resources and DECs were 14.2 percent of marginal resources in the first six months of 2020.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer, and the cost-based offer excluding the 10 percent adder. Table 3-103 shows the markup component of LMP for marginal generating resources. Generating resources were only 19.2 percent of marginal resources in the first six months of 2020. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $0.52 to $0.02 per MWh and decreased for gas fired CC units from $1.27 to $0.99 per MWh.

Table 3-103 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through June, 2019 and 2020

		2019 (Jan - Jun)			2020 (Jan - Jun)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	($0.24)	$0.52	42.1%	($0.67)	$0.02	34.0%
Gas	CC	$0.69	$1.27	51.6%	$0.59	$0.99	57.6%
Gas	CT	$0.02	$0.03	0.9%	($0.00)	$0.00	0.6%
Gas	RICE	($0.00)	($0.00)	0.5%	($0.00)	($0.00)	0.1%
Gas	Steam	($0.02)	$0.00	3.0%	($0.05)	($0.03)	2.2%
Municipal Waste	RICE	$0.00	$0.00	0.1%	$0.00	$0.00	0.1%
Oil	CT	$0.00	$0.00	0.1%	$0.00	($0.00)	0.2%
Oil	Steam	$0.00	($0.00)	0.0%	$0.00	$0.00	0.0%
Other	Solar	$0.00	$0.00	0.1%	$0.00	$0.00	0.2%
Other	Steam	($0.00)	($0.00)	0.1%	($0.00)	($0.00)	0.7%
Uranium	Steam	$0.00	$0.00	0.3%	$0.00	$0.00	1.7%
Wind	Wind	$0.02	$0.02	1.3%	$0.01	$0.01	2.8%
Total		$0.48	$1.83	100.0%	($0.14)	$0.99	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-104 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In the first six months of 2020, when using unadjusted cost-based offers, -$0.14 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2020, the peak markup component was highest in June, $0.39 per MWh using unadjusted cost-based offers.

Table 3-104 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2019 through June 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.78	$1.68	($0.16)	($0.03)	$0.29	($0.35)
Feb	$0.60	$0.80	$0.41	($0.23)	($0.08)	($0.39)
Mar	$0.65	$0.99	$0.32	($0.21)	($0.19)	($0.23)
Apr	$0.15	$0.30	($0.03)	($0.27)	($0.19)	($0.36)
May	$0.11	$0.13	$0.09	($0.19)	$0.17	($0.52)
Jun	$0.45	$0.38	$0.53	$0.07	$0.39	($0.33)
Jul	$2.50	$4.14	$0.66			
Aug	$0.39	$0.44	$0.34			
Sep	($0.09)	($0.28)	$0.09			
Oct	$1.11	$1.82	$0.25			
Nov	$1.71	$1.75	$1.68			
Dec	($0.34)	$0.21	($0.87)			
Annual	$0.48	$0.74	$0.19	($0.14)	$0.08	($0.36)

Table 3-105 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first six months of 2020, when using adjusted cost-based offers, $0.99 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2020, the peak markup component was highest in January, $1.65 per MWh using adjusted cost-based offers.

Table 3-105 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2019 through June 2020

	2019			2020		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.46	$3.34	$1.55	$1.35	$1.65	$1.03
Feb	$2.12	$2.35	$1.88	$1.03	$1.22	$0.84
Mar	$2.02	$2.28	$1.78	$0.96	$1.02	$0.90
Apr	$1.26	$1.28	$1.24	$0.70	$0.91	$0.47
May	$1.29	$1.17	$1.43	$0.72	$1.00	$0.47
Jun	$1.64	$1.62	$1.67	$1.05	$1.35	$0.67
Jul	$3.67	$5.17	$2.00			
Aug	$1.55	$1.48	$1.64			
Sep	$1.06	$0.81	$1.32			
Oct	$2.02	$2.55	$1.36			
Nov	$2.92	$3.01	$2.84			
Dec	$1.12	$1.65	$0.61			
Annual	$1.83	$2.05	$1.61	$0.99	$1.22	$0.75

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-106. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-107. The smallest zonal all hours average markup component using adjusted cost-based offers for the first six months of 2020 was in the Dominion Zone, $0.73 per MWh, while the highest was in the PPL Control Zone, $1.91 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the Dominion Control Zone, $0.88 per MWh, while the highest was in the PPL Control Zone, $2.24 per MWh.

Table 3-106 Day-ahead, average, zonal markup component (Unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.00	$1.44	$0.56	$0.09	$0.25	($0.06)
AEP	$0.38	$0.63	$0.12	($0.30)	($0.10)	($0.51)
APS	$0.41	$0.64	$0.18	($0.25)	($0.03)	($0.47)
ATSI	$0.37	$0.57	$0.15	($0.24)	($0.05)	($0.44)
BGE	$0.16	$0.38	($0.06)	($0.27)	$0.10	($0.65)
ComEd	$0.34	$0.48	$0.20	($0.23)	$0.01	($0.49)
DAY	$0.29	$0.49	$0.08	($0.12)	$0.24	($0.51)
DEOK	$0.27	$0.50	$0.03	$0.07	$0.64	($0.53)
DLCO	$0.36	$0.56	$0.15	($0.31)	($0.14)	($0.49)
Dominion	$0.24	$0.48	($0.00)	($0.39)	($0.28)	($0.49)
DPL	$0.98	$1.35	$0.61	$0.14	$0.32	($0.04)
EKPC	$0.46	$0.71	$0.22	($0.12)	$0.26	($0.50)
JCPL	$0.93	$1.36	$0.46	$0.05	$0.19	($0.11)
Met-Ed	$0.71	$1.12	$0.27	$0.08	$0.23	($0.07)
OVEC	$0.96	$1.26	$0.60	$0.05	$0.03	$0.10
PECO	$1.00	$1.46	$0.52	$0.09	$0.25	($0.08)
PENELEC	$0.65	$0.89	$0.39	$0.07	$0.25	($0.15)
Pepco	$0.19	$0.41	($0.04)	($0.40)	($0.24)	($0.57)
PPL	$0.89	$1.31	$0.45	$0.86	$1.18	$0.52
PSEG	$0.98	$1.42	$0.51	$0.06	$0.21	($0.11)
RECO	$0.78	$1.24	$0.27	$0.12	$0.37	($0.15)

Table 3-107 Day-ahead, average, zonal markup component (Adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)			2020 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.31	$2.69	$1.92	$1.20	$1.39	$1.02
AEP	$1.74	$1.94	$1.54	$0.86	$1.05	$0.66
APS	$1.78	$1.96	$1.60	$0.88	$1.14	$0.62
ATSI	$1.75	$1.91	$1.59	$0.91	$1.12	$0.68
BGE	$1.58	$1.75	$1.40	$0.86	$1.22	$0.49
ComEd	$1.65	$1.78	$1.51	$0.88	$1.13	$0.60
DAY	$1.72	$1.88	$1.55	$1.05	$1.39	$0.68
DEOK	$1.66	$1.82	$1.50	$1.17	$1.68	$0.64
DLCO	$1.74	$1.89	$1.58	$0.80	$0.99	$0.60
Dominion	$1.63	$1.80	$1.46	$0.73	$0.88	$0.58
DPL	$2.29	$2.57	$2.01	$1.24	$1.42	$1.05
EKPC	$1.83	$2.04	$1.62	$1.00	$1.35	$0.67
JCPL	$2.29	$2.67	$1.87	$1.18	$1.35	$1.00
Met-Ed	$2.06	$2.38	$1.71	$1.20	$1.38	$1.01
OVEC	$1.96	$2.06	$1.83	$1.16	$1.16	$1.15
PECO	$2.33	$2.72	$1.91	$1.20	$1.39	$1.01
PENELEC	$1.97	$2.15	$1.78	$1.11	$1.33	$0.86
Pepco	$1.61	$1.79	$1.42	$0.77	$0.97	$0.56
PPL	$2.22	$2.57	$1.84	$1.91	$2.24	$1.56
PSEG	$2.28	$2.66	$1.87	$1.16	$1.33	$0.98
RECO	$2.12	$2.48	$1.71	$1.20	$1.44	$0.94

Markup by Day-Ahead Price Levels

Table 3-108 and Table 3-109 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-108 Average, day-ahead markup component (By LMP category, unadjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.0%	$0.00	1.5%
$10 to $15	$0.01	2.0%	($0.05)	19.0%
$15 to $20	$0.03	16.1%	($0.22)	47.8%
$20 to $25	($0.07)	31.2%	$0.03	23.4%
$25 to $50	$0.34	48.5%	$0.11	8.2%
$50 to $75	$0.05	1.2%	$0.00	0.1%
$75 to $100	$0.05	0.8%	$0.00	0.0%
$100 to $125	$0.03	0.1%	$0.00	0.0%
$125 to $150	$0.02	0.0%	$0.00	0.0%
>= $150	$0.02	0.0%	$0.00	0.0%

Table 3-109 Average, day-ahead markup component (By LMP category, adjusted): January through June, 2019 and 2020

	2019 (Jan - Jun)		2020 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.0%	$0.01	1.5%
$10 to $15	$0.02	2.0%	$0.09	19.0%
$15 to $20	$0.19	16.1%	$0.36	47.8%
$20 to $25	$0.37	31.2%	$0.35	23.4%
$25 to $50	$1.04	48.5%	$0.18	8.2%
$50 to $75	$0.07	1.2%	$0.00	0.1%
$75 to $100	$0.06	0.8%	$0.00	0.0%
$100 to $125	$0.04	0.1%	$0.00	0.0%
$125 to $150	$0.03	0.0%	$0.00	0.0%
>= $150	$0.02	0.0%	$0.00	0.0%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment determines the extent to which that participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[133]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, P is the market price, and MC is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. If HHI is very low, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices approach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[134] Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[135]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of \$19.05 per MWh and an average HHI of 748 in the first six months of 2020, average PJM prices would theoretically range from \$23 to \$30 per MWh using the elasticity range of -0.2 to -0.4.[136] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging \$19.40 per MWh, and markups, at 1.8 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

133 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

134 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices, <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

135 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

136 The average HHI is found in Table 3-1. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3--51.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-110 categorizes real-time marginal unit intervals by markup level and TPS test status. In the first six months of 2020, 7.0 percent of marginal unit intervals included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit. The 7.0 percent of marginal unit intervals failing the TPS test with unmitigated positive markup exceeds the 1.9 percent of marginal unit intervals failing the TPS with zero markup. Marginal units with positive markup are mitigated less often than not.

Table 3-110 Percent of real-time marginal unit intervals with markup and local market power: January through June, 2020

Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	31.4%	5.3%	36.7%
Zero Markup	10.5%	1.9%	12.5%
$0 to $5	37.5%	6.3%	43.7%
$5 to $10	4.8%	0.5%	5.3%
$10 to $15	0.5%	0.1%	0.6%
$15 to $20	0.2%	0.0%	0.3%
$20 to $25	0.4%	0.0%	0.4%
$25 to $50	0.3%	0.0%	0.3%
$50 to $75	0.1%	0.0%	0.1%
$75 to $100	0.0%	0.0%	0.0%
Above $100	0.1%	0.1%	0.1%
Total Positive Markup	43.8%	7.0%	50.8%
Total	85.8%	14.2%	100.0%

The markup of marginal units is zero or negative in 49.2 percent of marginal unit intervals in 2020. The flaws in the offer capping process that allow positive markups to affect prices in the presence of market power are a vulnerability to the overall competitiveness of the PJM energy market.

Attachment F

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

The MMU is also tracking PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2020 Quarterly State of the Market Report for PJM: January through June*, the MMU includes three new recommendations.

New Recommendation from Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all units going into service since the change in the tax code. The CRF rates should be updated at least annually to reflect current interest rates and changes in federal or state taxes, including depreciation treatment and tax rates. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources and the current tax rate and interest rate. (Priority: High. New recommendation. Status: Not adopted.)

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

New Recommendation from Section 13, Financial Transmission Rights and Auction Revenue Rights

- The MMU recommends a requirement that the details of all bilateral transactions be reported to PJM. (Priority: High. New recommendation. Status: Not adopted.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported 2018. Status: Not adopted.)

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Adopted 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000

per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- The MMU recommends that market sellers not be allowed to designate any portion of an available capacity resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[7] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Adopted 2020.)

7 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[8] [9] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)

8 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

9 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including modeling soak time for units with a steam turbine and configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported Q1, 2020. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Adopted, 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based, scheduled approach. (Priority: High. First reported 2018. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Partially adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead operating reserves to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends that self scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[10])
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the day-ahead and the real-time energy markets and the associated operating reserve charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[11])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch.

10 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Volume 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

11 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Section 5, Capacity Market

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[12] [13] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[14] [15] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity

12 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
13 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
14 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
15 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[16] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and

16 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

17 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 6, Demand Response

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component

of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)

- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[18] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[19] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends limited, extended summer and annual demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)

18 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

19 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[20])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)

20 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency MW not be included in the PJM Capacity Market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported Q1 2020. Status: Not adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the day-ahead and real-time energy markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: High. First reported 2013. Status: Partially adopted, Q2 2020.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SouthIMP/EXP interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends changing the assignment of the Saskatchewan Power Company and Manitoba Hydro balancing authorities from the Northwest interface pricing point to the MISO interface pricing point and eliminating the Northwest interface pricing point from the day-ahead and real-time energy markets. (Priority: High. First reported Q1, 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the NCMPAIMP and NCMPAEXP interface pricing points. It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing

authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 10, Ancillary Services

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[21])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[22] FERC rejected.[23])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[24])

21 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
22 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
23 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
24 *Id.*

- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[25])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[26])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Partially Adopted 2019.)
- The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)

25 *Id.*
26 *Id.*

- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR market be based on opportunity cost only in order to mitigate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all units going into service since the change in the tax code. The CRF rates should be updated at least annually to reflect current interest rates and changes in federal or state taxes, including depreciation treatment and tax rates. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources and the current tax rate and interest rate. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[27] Status: Partially adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[28] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. Status: Adopted, 2019.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to

27 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

28 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Adopted.)

Cost Allocation

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[29] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

29 See the *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)

- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[30] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Adopted, 2019. Pending at FERC.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral transactions be reported to PJM. (Priority: High. New recommendation. Status: Not adopted.)

30 See "PJM Manual 6: Financial Transmission Rights," Rev. 24 (April 15, 2020).