Monitoring Analytics

Analysis of the 2024/2025 RPM Base Residual Auction

The Independent Market Monitor for PJM

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Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the eighteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2024/2025 Delivery Year which was held from December 7 to 13, 2022, and responds to questions raised by PJM members and market observers about that auction.[1] The results for the 2024/2025 RPM Base Residual Auction were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[2] The MMU prepares a report for each RPM Base Residual Auction.

This report addresses, explains and quantifies the basic market outcomes in the 2024/2025 BRA. This report also addresses and quantifies the impact on market outcomes of: the shape of the existing VRR curve; a VRR rotated half way towards a vertical curve; the overstatement of forecast peak load; the overstatement of intermittent capacity values; the inclusion of Demand Resources (DR); the inclusion of Energy Efficiency resources (EE) and the EE addback mechanism; the inclusion of Price Responsive Demand (PRD); the inclusion of seasonal products; the use of seasonal matching; the inclusion of capacity imports; and offers for nuclear resources.[3]

The combined impact of four core flaws in the market design and in the definition of capacity was to reduce capacity market revenues by 53.8 percent in the 2024/2025 BRA. The four core flaws are: the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

This report also addresses additional issues including: market power; the market seller offer cap (MSOC); MOPR; the capacity must offer requirement; the definition of avoidable costs; the use of forward looking net revenues; the matching of seasonal offers; Capacity Transfer Rights (CTRs); the definition of reliability that leads to RMRs; and the market clearing model used by PJM.

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1 The BRA for the 2024/2025 Delivery Year had been scheduled for May 2021.

2 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.

3 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.

The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[4] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[5] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. The corrected MSOC rules were applied in the 2023/2024 BRA and the 2024/2025 BRA and were essential to the competitive results of the 2023/2024 BRA and the 2024/2025 BRA.

Only 2.2 percent of offers (21 generation resources) requested unit specific avoidable cost review for the 2024/2025 Base Residual Auction, of which only 0.6 percent (six resources) requested a CPQR. Only a very small proportion of that 2.2 percent did not reach agreement with the MMU. The MMU calculated offer caps for 742 generation resources that submitted capacity offers, most of which (96.4 percent) were default ACR based.

The MMU concludes that the results of the 2024/2025 Base Residual Auction were competitive.

Capacity market prices in the 2024/2025 BRA were the result of both competitive forces and significantly flawed market design. The corrected MSOC rules resulted in competitive offers and prevented noncompetitive offers. Some elements of the market design suppressed prices. The lower clearing prices in 2024/2025 BRA compared to the 2023/2024 BRA were primarily the result of lower offer prices.

The capacity market exists to make the energy market work, by providing the additional net revenues required for the incentive to invest in new units and to maintain old units. The definition of capacity is not the ability to provide energy during one peak hour or five peak hours, as implied by the methods used by PJM and LSEs to allocate the costs of capacity to load. The obligations of capacity resources include the requirement to offer

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4 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

5 176 FERC ¶ 61,137 (September 2nd Order).

their full ICAP in the energy and reserves markets every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year. Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market.[6] Under that approach, products with different characteristics at different times of the year (so called seasonal products) would not need to be matched with peak period products.

Conclusions

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets frequently 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 from the full set of PJM 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. Capacity in excess of demand means capacity in excess of the demand as defined by the capacity demand curve, called the Variable Resource Requirement (VRR) curve. PJM rules require load to pay for the level of capacity defined by the VRR curve. But, correctly defined, excess capacity means capacity in excess of the peak load forecast plus the reserve margin, the level of capacity PJM is required to purchase in order to maintain reliability.

PJM's required demand for capacity, based on reliability requirements, includes expected peak load plus a required reserve margin, but most points on the downward sloping part of the demand curve, the VRR curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and substantially higher payments by customers. The required demand for capacity defines a vertical demand curve equal to expected peak load plus a required reserve margin. The impact of the VRR curve shape used in the 2024/2025 BRA compared to a vertical demand curve was significant. Use of the VRR curve resulted in the purchase of capacity that was 5.8 percent in excess of the reliability requirement, and increased the total load payments for capacity by $815 million, an increase of 59.2 percent compared to a vertical demand curve.

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6 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

The level of cleared demand resources (8,083.9 MW) is almost exactly equal to the entire excess (8,086.8 MW). PJM has not, and is not, relying on demand response for reliability in actual operations. The excess capacity that PJM routinely requires load to buy has hidden the impact of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the full implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI, and associated energy market prices, whenever called.

The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and the VRR defined 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 means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[7] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and

[7] See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions. The market power rules were corrected by the Commission in an order issued on September 2, 2021, (September 2nd Order) but the modified market power rules were not implemented in the 2022/2023 BRA.[8] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA.

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 market seller offer cap defines a competitive offer in the capacity market, regardless of whether the concern is efforts to increase the market price above the competitive level or to reduce the market price below the competitive level. It is basic economics that a competitive offer is a competitive offer. There is not one competitive offer for those who would suppress market prices and another one for those would inflate market prices. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[9] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and

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8 176 FERC ¶ 61,137 (September 2nd Order).

9 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.

all other resources that clear the market will be compensated at that Net CONE price."[10] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[11] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[12] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[13] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate (360) is the same as the expected PAI; the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

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10 See page 55 of CP Filing.

11 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.

12 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).

13 See page 43 of CP Filing.

The MMU supported the modified CP filing and prepared the mathematical appendix.[14] But, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[15] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[16] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[17] [18]

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14 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).

15 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

16 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

17 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").

18 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

The MMU, as part of the process for all RPM auctions, verifies the reasonableness of avoidable cost data and calculations; calculates unit specific net revenues; calculates the derived offer caps based on submitted data for resources that submitted unit specific data and for resources that submitted offers based on default ACR values; reviews Minimum Offer Price Rule (MOPR) unit specific exception requests; reviews offers for Planned Generation Capacity Resources; verifies capacity exports, including firm contracts and export offers based on opportunity costs; reviews requests for exceptions to the RPM must offer requirement; reviews requests for exceptions to the additional, specific CP must offer requirement; verifies the sell offer Equivalent Demand Forced Outage Rates (EFORds); reviews requests for alternate maximum EFORds; reviews documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; verifies clearing prices based on the supply and demand (VRR) curves; and verifies that the market power tests were applied correctly.[19]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, MAAC, EMAAC, DPL South, BGE, and DEOK 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.[20] [21]

Based on the data and this review, the MMU concludes that the results of the 2024/2025 RPM Base Residual Auction were competitive. A competitive offer in the capacity market

19 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.

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

21 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).

is equal to net ACR.[22] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2024/2025 auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[23] Although the impact did not arise in the 2024/2025 auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Recommendations

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. 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 pre-CP capacity market design be strengthened by, among other things, eliminating the incorrect definition of forced outages. The MMU had recommended 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. 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, although this recommendation has not been incorporated in PJM rules. 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

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22 174 FERC ¶ 61,212 ("March 18th Order") at 65.

23 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk.[24]

The MMU recommends that PJM evaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement as a transition step in the 2022 Quadrennial Review.[25] The shape of the VRR curve was discussed in the stakeholder process. PJM reviewed the impact of a range of VRR shape options in the 2022 Quadrennial Review, and PJM agreed that the VRR curve should be rotated towards the vertical demand curve, but by only approximately one quarter of the way towards vertical.[26] That change will be implemented in the 2026/2027 BRA.[27]

The MMU recommends that PJM not sell back any capacity in any IA, at much lower prices, procured in a BRA. If excess capacity is procured in a BRA at very significant cost to load, that capacity should not be sold back at a steep discount. Given PJM's assertions of the benefits of over procuring capacity, it has never been explained why load should pay a high price for capacity in a BRA and sell it back at very low prices in an IA. Such sales are inconsistent with PJM's assertion that additional capacity purchases have

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24 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," (August 16, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>. See additional related MMU presentations at <https://www.monitoringanalytics.com/reports/Presentations/2023.shtml>

25 See *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Docket No. ER22-2984-000 (November 16, 2022).

26 See PJM Filing, Docket ER22-2984-000 (September 30, 2022) at 9; MIC Special Sessions: 2022 Quadrennial Review.

27 182 FERC ¶ 61,073 (February 14, 2023).

value.[28] In addition, such sales suppress prices in incremental auctions and provide inefficient incentives for demand resource offer behavior and an inefficient incentives to replace capacity sales.[29]

The MMU recommends the enforcement of a consistent definition of a 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, including planned generation, demand resources, energy efficiency, and imports.[30] [31] The requirement to be a physical resource is not currently applied to DR and EE, both of which are permitted to submit marketing plans rather than evidence of physical resources in the BRA. All DR should be on the demand side of the market rather than on the supply side. If DR remains on the supply side, it should be required to be an economic resource rather than a purely emergency resource and to have all the obligations of any other capacity resource. EE should be removed from the capacity market because it is now accounted for in PJM load forecasts. In addition, the rules governing the actual EE resources are inadequate to ensure that the significant payments by capacity market customers are changing any actual behavior by EE program participants.

The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed the CIRs assigned to such resources. In the 2023/2024 and 2024/2025 BRAs, intermittent resource offers were overstated because they were based on an assumed level of delivered energy in excess of CIRs. Correctly defined derating factors will be lower than the CIRs required to meet those

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28 "PJM Manual 18: PJM Capacity Market," § 3.1 Overview of Demand in the Reliability Pricing Model, Rev. 55 (Feb. 9, 2023).

29 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).

30 See *PJM Interconnection, L.L.C,* Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000. (December 20, 2013).

31 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).

derating factors because energy deliveries at full output (the appropriate required CIR level) are included in the determination of the derating factors.[32] It is not adequate that intermittent resources, including storage, not be permitted to offer capacity MW greater than the CIR values assigned to and, when required, paid for by such resources. For intermittent resources, including storage, that is a necessary but not sufficient condition for the correct level of capacity MW. Correctly defined derating factors are lower than the required CIRs.

The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM's practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[33] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR and EE, were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and is also denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The same logic should be applied to intermittent and storage resources. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases. The failure to apply the must offer requirement consistently could also result in very significant changes in

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32 This conclusion was the result of lengthy stakeholder discussions in the Capacity Capability Senior Task Force <https://pjm.com/committees-and-groups/closed-groups/ccstf> and the Planning Committee (PC) Special Session – CIRs for ELCC Resources <https://www.pjm.com/committees-and-groups/committees/pc>.

33 See "Executive Summary of IMM Capacity market design proposal: Sustainable Capacity Market (SCM)," IMM presentation to the PJM Board of Managers, (August 23, 2023) <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

It is not clear why intermittents and storage were exempted to date, but as the role of intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The capacity market has included balanced must buy and must sell obligations from its inception.

The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity whether a new resource or an existing resource. The tariff distinction between mothball and retirement avoidable costs is unsupported and should be eliminated. Avoidable costs are defined by the OATT to be the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[34] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate in the delivery year.

The MMU also recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[35] The definition of avoidable costs was modified by PJM effective April 15, 2019, to exclude major maintenance costs.[36] This change was applicable starting with the 2022/2023 Delivery Year if these costs had been previously included in unit specific ACR by a capacity market seller or effective as early as the 2020/2021 Delivery Year if these costs had not been previously included in unit specific ACR by a capacity

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34 OATT Attachment DD § 6.8 (b).

35 *PJM Interconnection L.L.C.*, Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery (February 14, 2019).

36 167 FERC ¶ 61,030 (April 15, 2019).

market seller.[37] The result was to reduce gross ACR values and to reduce offer caps in the capacity market below the competitive level.

The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's peak load forecasts now account for EE, and the rationale for inclusion no longer exists. EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets to the extent that it reduces energy and capacity use and therefore customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original reason for the inclusion of EE in the capacity market no longer exists. While EE does not affect the clearing price when the EE addback is done correctly, customers do pay for the cleared quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers.

The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. This recommendation was rejected by FERC.[38] The FERC approved approach, used in the 2021/2022, 2022/2023, 2023/2024 and 2024/2025 BRAs, requires use of the price-based offer in most cases. The FERC approach requires the use of the cost-based offer when the resource offer is mitigated for market power and the cost-based offer is lower than the price-based offer. The FERC approach also requires the use of the cost-based offer when 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.[39] The higher the energy offer used in the calculation of net revenues, the lower the net revenues and the higher the net ACR offer cap. The FERC approach, used in most cases, results in lower net revenues and higher offer caps than calculated under the MMU approach.

The MMU recommends the use of a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years.

But the current PJM method for calculating forward looking E&AS net revenues includes an adjustment based on the prices of long term FTRs for the planning period closest in

37 OATT Attachment DD § 6.8 (c).

38 See 155 FERC ¶ 61,281 (2016).

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

time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. The MMU recommends the use of forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[40]

The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. 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. A fully flexible offer or an inflexible offer of the entire unit may each be competitive offers, depending on the economic status of the unit. The use of segments not linked to the physical characteristics of units permits the exercise of market power through impacts on clearing prices and by requiring uplift payments when an entire segment or resource is not required in order to clear the market.

The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping.

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

40 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 42 (Oct. 28, 2022).

modeling assumptions.[41] This was a significant issue in the review of MOPR offer floors in the 2022/2023 BRA.

The MMU recommends that the RPM market power mitigation rules 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 in order to ensure that market power does not result in an increase in uplift payments for seasonal products. The RPM rules require that offer caps be applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller fails the three pivotal supplier test, the submitted sell offer exceeds the defined offer cap, and the submitted sell offer, absent mitigation, would result in a higher market clearing price.[42] Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

The MMU recommends that any combined seasonal products be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. The CTR issue also highlights a broader issue with differences between overall market clearing results and settlements for individual LDAs.

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41 *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).

42 OATT Attachment DD § 6.5.

The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results.

The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. CETL is relevant for transfers between LDAs and for imports to PJM. The MMU recommends that CETL include the ability to import capacity from outside PJM only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. These imports could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to derive CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. The review of actual offers in the 2024/2025 Base Residual Auction revealed a substantial flaw in the design of the capacity market. A significant level of capacity located in the DPL South LDA that PJM had assumed would be offered in the BRA did not offer. PJM's reliability requirement for the DPL South was calculated based on the assumption that the proposed generation capacity resources that had completed PJM's interconnection service agreement at the time of the CETO calculation would be available to satisfy the DPL South LDA's target reliability criteria of less than one loss of load event in 25 years. The incorrect projected generation capacity in DPL South LDA resulted in an overstated CETO and reliability requirement for the DPL South LDA. Prior to clearing the auction and posting prices, PJM requested that FERC allow PJM to correctly reflect the actual capacity offers and the associated revised CETO and reliability requirement of the DPL South LDA for the 2024/2025 RPM Base Residual Auction. PJM also requested a tariff change to provide PJM the authority to revise the CETO and reliability requirement of any LDA in the future for similar situations. FERC approved PJM's request, and PJM posted the auction clearing results on February 27, 2023. [43]

The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, 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 to PJM load. If capacity resources cannot be identified as deliverable to PJM load in an identified LDA, the import is not a capacity resource for PJM and should not be allowed. Simply attributing capacity imports to the Rest of RTO LDA does not constitute identifying the specific LDA that the resource is deliverable to. All internal capacity resources are deliverable to a specific LDA.

The MMU recommends that PJM implement a nodal capacity market in order to ensure that transmission constraints and locational economic fundamentals are accurately reflected in capacity market prices. 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. In addition, the CETO/CETL analysis does not include transmission constraints internal to the modeled LDA. The entire LDA is also modeled as a single node. Modeled LDAs can be quite large and internal transmission constraints can be significant. The absence of modeled internal constraints could result in the inability to deliver capacity from one part of an LDA to another part of an 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 between LDAs.

43 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.

The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. Such a result means that the market design is flawed. Such a result implies that the capacity market uses different reliability standards than transmission planning. That is inappropriate. The two standards should be the same.

The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function. Adoption of the additional MMU recommendation that all capacity offers be fully flexible, unless there is a physical reason for segments, would also significantly reduce or eliminate this problem.

Summary of Results

As shown in Table 15 and Table 16, the 139,810.2 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 21.7 percent and a net excess of 8,086.8 MW over the reliability requirement adjusted for FRR and PRD of 131,723.4 MW.[44] [45] Net excess increased 251.5 MW from the net excess of 7,835.3 MW in the 2023/2024 RPM Base Residual Auction. As shown in Figure 2, the intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $28.92 per MW-day for the rest of RTO.

Table 1 and Table 2 summarize the sensitivity analyses.

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the auction results. 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 set equal to the reliability requirement. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If PJM had used a vertical demand curve set equal to the reliability requirement for the 2024/2025 BRA and everything else had remained the same, total RPM market revenues for the 2024/2025 BRA would have been $1,377,668,211, a decrease of $815,160,040, or 37.2 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in an 59.2

[44] The 21.7 percent reserve margin does not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. The 21.7 percent reserve margin also does not include the 26.7 MW of uplift. This is how PJM calculates the reserve margin.

[45] These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

percent increase in RPM revenues for the 2024/2025 RPM BRA compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement. (Scenario 1)

The downward sloping shape of the VRR curve had a significant impact on the auction results. As a result of the flatter downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a steeper demand curve set at half way between the VRR curve used in the 2024/2025 BRA and the vertical demand curve defined by the reliability requirement. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If PJM had used a VRR curve set at half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,712,525,223, a decrease of $480,303,029, or 21.9 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 28.0 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a VRR curve set at half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement. (Scenario 2)

The accuracy of the peak load forecast (MW) had a significant impact on the auction results.[46] [47] An analysis of the RPM auctions for the 2017/2018 through 2022/2023 Delivery Years shows that the peak load forecast (MW) for the Third Incremental Auction has been on average 2.0 percent lower (MW) than the peak load forecast (MW) used for the corresponding Base Residual Auction. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the peak load forecast MW for the 2024/2025 RPM Base Residual Auction had been 2.0 percent lower and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,800,931,369, a decrease of $391,896,882, or 17.9 percent, compared to the

46 Five years of load forecast data are used to calculate the average forecast error. Three of the last five BRAs were held approximately three years prior to the delivery year while the 2023/2024 BRA was held approximately one year prior to the delivery year and the 2024/2025 BRA was held approximately one and a half years prior to the delivery year.

47 PJM's 2023 load forecast model was updated to incorporate recommendations from Itrón. See Load Forecast Model Development Item 5 in the meeting materials for the Load Analysis Subcommittee, PJM L.L.C., October 27, 2022 <https://pjm.com/committees-and-groups/subcommittees/las>.

actual results. From another perspective, using PJM's peak load forecast (MW) for the 2024/2025 Base Residual Auction resulted in a 21.8 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 2.0 percent below the PJM peak load forecast. (Scenario 3)

The overstatement of the capacity value of intermittent resources had a significant impact on the auction results. As a result of the inclusion of overstated intermittent resources, capacity market prices were lower than if the ELCC had been defined correctly. As a sensitivity to calculate that impact of overstating the capacity value of wind and solar generators, the MMU reduced the MW value associated with all solar offers by 20.0 percent and the MW value associated with annual and summer wind offers by 48.9 percent based on an MMU analysis.[48] Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the unforced capacity of solar and wind resources offered in the 2024/2025 RPM Base Residual Auction had been appropriately reduced as defined, and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,272,074,858, an increase of $79,246,607, or 3.6 percent, compared to the actual results. From another perspective, the inclusion of overstated offers from solar and wind resources resulted in a 3.5 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if offered MW from solar had been reduced by 20 percent and offered MW from wind resources had been reduced by 48.9 percent. (Scenario 4)

The inclusion of all sell offers for demand resources, including annual and seasonal, had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2022/2023 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for DR in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $5,248,970,191, an increase of $3,056,141,939, or 139.4 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 58.2 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without any DR. (Scenario 5)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results, but not on the auction clearing prices. Based on actual

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48 These derates are based on an MMU study from 2022. See page 8 in "Intermittent Output and CIRs," IMM, PC Special Session – CIRs for ELCC Resources (February 23, 2022) <https://pjm.com/committees-and-groups/committees/pc>.

auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there were no offers for EE and the EE addback MW were removed in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,073,286,830, a decrease of $119,541,421, or 5.5 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW, resulted in a 5.8 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE did not participate on the supply side. (Scenario 6)

The 2024/2025 RPM Base Residual Auction was the fifth 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 uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no submissions from PRD providers in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,259,815,834, an increase of $66,987,582, or 3.1 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 3.0 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without any PRD. (Scenario 7)

The 2024/2025 RPM Base Residual Auction was the fourth BRA held using the seasonal products for summer and winter capacity. The inclusion of seasonal offers (summer period capacity performance resources or winter period capacity performance resources) had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for seasonal products in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,296,212,168, an increase of $103,383,917, or 4.7 percent, compared to the actual results. From another perspective, the inclusion of seasonal offers resulted in a 4.5 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without any seasonal offers. (Scenario 8)

Matching seasonal offers across LDAs had a limited impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If seasonal offers were not matched with complementary seasonal offers from other LDAs in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $2,197,384,603, an increase of $4,556,351 or 0.2 percent, compared to the actual results. From another perspective, allowing the matching of offers with complementary seasonal offers from other LDAs resulted in a 0.2 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if seasonal offers were only matched with complementary seasonal offers within the same LDA. (Scenario 9)

The inclusion of capacity imports in the 2024/2025 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If offers for external generation had been eliminated and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,400,001,217, an increase of $207,172,966, or 9.4 percent, compared to the actual results. From another perspective, the impact of including capacity imports resulted in a 8.6 percent reduction in RPM revenues for the 202/2025 RPM Base Residual Auction compared to what RPM revenues would have been if no capacity imports were included in the auction. (Scenario 10)

The combined impact of issues related to the definition of capacity had a significant impact on the auction results. Together, the overstatement of intermittent MW offers, and the inclusion of sell offers from demand resources, EE, PRD, seasonal products, and imports had a significant combined impact on the auction results. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no overstatement of intermittent MW offers and no offers from demand resources, EE, PRD, seasonal products, or imports in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $8,374,917,524, an increase of $6,182,089,273, or 281.9 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from demand resources, EE, PRD, seasonal products and imports resulted in a 73.8 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without overstated intermittent MW offers, and offers from demand resources, EE, PRD, seasonal products and imports. (Scenario 11)

The MMU analyzed the impact of capacity that was categorically exempt from the RPM must offer obligation and that did offer into the 2024/2025 RPM Base Residual Auction.[49] Capacity offers for resources that were categorically exempt from the RPM must offer

[49] Intermittent and storage resources are categorically exempt from the must offer requirement. Capacity storage resources include hydroelectric, flywheel and battery storage. Intermittent resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources.

requirement had a significant impact on the auction results. This scenario is the case where no categorically exempt resources offered. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for capacity resources categorically exempt from RPM must offer requirement in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $5,200,707,712, an increase of $3,007,879,460, or 137.2 percent, compared to the actual results. From another perspective, the inclusion of offers for capacity resources categorically exempt from RPM must offer requirement resulted in a 57.8 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without offers from capacity resources categorically exempt from RPM must offer requirement (Scenario 12).

The MMU also analyzed the impact of capacity that was categorically exempt from the RPM must offer obligation and that did not offer into the 2024/2025 RPM Base Residual Auction.[50] Capacity resources that were categorically exempt from the RPM must offer requirement and did not offer in the 2024/2025 RPM Base Residual Auction had a significant impact on the auction results. This scenario is the case where all categorically exempt resources were assumed to be offered at $0 per MW-day. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,921,538,019, a decrease of $271,290,232, or 12.4 percent, compared to the actual results. From another perspective, the failure to offer of some capacity that was categorically exempt from the RPM must offer requirement resulted in a 14.1 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement (Scenario 13).

Nuclear offer behavior in the 2024/2025 RPM Base Residual Auction had a significant impact on the auction results. Nuclear offer behavior in the 2024/2025 RPM Base Residual Auction was significantly different from that in the 2022/2023 BRA. In both the 2021/2022

50 Intermittent and storage resources are categorically exempt from the must offer requirement. Capacity storage resources include hydroelectric, flywheel and battery storage. Intermittent resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources.

and the 2022/2023 BRA, a significant level of nuclear capacity was offered at higher prices than in the 2020/2021 BRA, and fewer nuclear MW cleared in the 2021/2022 BRA and the 2022/2023 BRA than in the 2020/2021 BRA.[51] 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 the competitive offer for all nuclear resources. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,121,788,593, a decrease of $71,039,658, or 3.2 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 3.3 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day. (Scenario 14)

The combined impact of four specific, identified core market design flaws was to reduce capacity market revenues by 53.8 percent in the 2024/2025 BRA (Scenarios 2, 4, 5 and 10). The impact of three of these identified market design flaws reduced capacity market prices (Scenarios 4, 5 and 10) and the impact of the other identified market design flaw increased capacity market prices (Scenario 2). The identified market design flaws are: the shape of the VRR curve (Scenario 2); the overstatement of intermittent MW offers (Scenario 4); the inclusion of sell offers from DR (Scenario 5); and the inclusion of capacity imports (Scenario 10). Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If all of the identified market design flaws had been corrected in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $4,749,749,993, an increase of $2,556,921,742, or 116.1 percent, compared to the actual results. From another perspective, the identified market design flaws resulted in a 53.8 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without those flaws (Scenario 15).

Summary Results Tables

Table 1 is a summary of the revenue impact of all the scenarios analyzed. The RPM Revenue column shows the revenues that resulted from the specific scenario only. The

51 See PJM. Markets and Operations. BRA Reports are organized by Delivery Years and are located at <https://www.pjm.com/markets-and-operations/rpm>. Associated press releases can be found at <https://www.pjm.com/about-pjm/newsroom/announcements-and-news-releases>.

Scenario Impact RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in RPM revenues. A negative number means that the specific scenario resulted in an increase in RPM revenues. The Percent columns show the percent change in RPM revenues for the specific scenario from two perspectives. The Scenario to Actual column, shows the difference between the revenues under the defined scenario and the actual auction revenues. The Actual to Scenario column shows the impact of changing the market rules to align with the scenario assumptions. For example, the Vertical VRR curve scenario shows the impact of using a vertical VRR curve rather than the actual downward sloping VRR curve. The RPM Revenue Change column shows that the difference in RPM revenue resulting from the use of a vertical demand curve would have been a decrease in RPM revenue equal to $815,160,040. The Actual to Scenario column shows that the use of the vertical VRR curve would have resulted in a reduction in RPM revenue of 37.2 percent compared to the actual RPM revenue. The Scenario to Actual column shows that the use of the downward sloping VRR curve resulted in an increase in RPM revenue of 59.2 percent compared to the RPM revenue with a vertical VRR curve.

Table 1 Scenario summary for 2024/2025 RPM Base Residual Auction: Impacts on RPM revenue[52]

			Scenario Impact		
			RPM Revenue	Percent Change	
		RPM Revenue	Change	Scenario	Actual to
Scenario	Scenario Description	($ per Delivery Year)	($ per Delivery Year)	to Actual	Scenario
0	Actual Results	$2,192,828,251	NA	NA	NA
1	Vertical VRR curve	$1,377,668,211	$815,160,040	59.2%	(37.2%)
2	VRR curve half way to vertical	$1,712,525,223	$480,303,029	28.0%	(21.9%)
3	Reduction in over forecasted peak load	$1,800,931,369	$391,896,882	21.8%	(17.9%)
4	Correction to overstated intermittent capacity	$2,272,074,858	($79,246,607)	(3.5%)	3.6%
5	Zero demand resources	$5,248,970,191	($3,056,141,939)	(58.2%)	139.4%
6	Zero EE offers and EE add back	$2,073,286,830	$119,541,421	5.8%	(5.5%)
7	Zero PRD offers	$2,259,815,834	($66,987,582)	(3.0%)	3.1%
8	Zero seasonal offers	$2,296,212,168	($103,383,917)	(4.5%)	4.7%
9	Matching seasonal offers only within LDAs	$2,197,384,603	($4,556,351)	(0.2%)	0.2%
10	Zero capacity imports	$2,400,001,217	($207,172,966)	(8.6%)	9.4%
11	Combined scenarios 4, 5, 6, 7, 8 and 10	$8,374,917,524	($6,182,089,273)	(73.8%)	281.9%
12	Zero categorically exempt offers	$5,200,707,712	($3,007,879,460)	(57.8%)	137.2%
13	All categorically exempt offers	$1,921,538,019	$271,290,232	14.1%	(12.4%)
14	All nuclear offers as price takers	$2,121,788,593	$71,039,658	3.3%	(3.2%)
15	Combined scenarios 2, 4, 5 and 10	$4,749,749,993	($2,556,921,742)	(53.8%)	116.6%

52 Scenario to Actual represents the impact of moving from the scenario to the actual BRA results and the percent change is *(Actual RPM Revenue less Scenario RPM Revenue) / (Scenario RPM*

Table 2 is a summary of the cleared UCAP MW impact of all the scenarios analyzed. The Cleared UCAP column shows the cleared MW that resulted from the specific scenario only. The Scenario Impact Cleared UCAP Change column shows the difference between the actual RPM cleared UCAP MW and the total RPM cleared UCAP MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in cleared RPM MW. A negative number means that the specific scenario resulted in an increase in cleared RPM MW. The Scenario Impact Cleared UCAP column shows the difference between the actual RPM cleared MW and the total RPM cleared MW that resulted from the specific scenario. A positive number means that the specific scenario resulted in a reduction in RPM cleared MW. A negative number means that the specific scenario resulted in an increase in RPM cleared MW. The Percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual column, shows the difference between the cleared MW under the defined scenario and the actual auction cleared MW. The Actual to Scenario column shows the impact of changing the market rules to align with the scenario assumptions. For example, the Vertical VRR curve scenario shows the impact of using a vertical VRR curve rather than the actual downward sloping VRR curve. The Cleared UCAP Change column shows that the difference in RPM cleared MW resulting from the use of a vertical demand curve would have been a decrease in RPM cleared MW equal to 8,086.8 MW. The Actual to Scenario column shows that the use of the vertical VRR curve would have resulted in a reduction in RPM cleared MW of 5.5 percent compared to the actual RPM cleared MW. The Scenario to Actual column shows that the use of the downward sloping VRR curve resulted in an increase in RPM cleared MW of 5.8 percent compared to the RPM cleared MW with a vertical VRR curve.

Revenue). The Actual to Scenario column represents the alternative perspective of the impact from moving from the actual BRA results to the scenario results and the percent change is *(Scenario RPM Revenue less Actual RPM Revenue) / (Actual RPM Revenue).*

Table 2 Scenario summary for 2024/2025 RPM Base Residual Auction: Impacts on RPM cleared UCAP MW[53]

			Scenario Impact		
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual Results	147,478.9	NA	NA	NA
1	Vertical VRR curve	139,392.1	8,086.8	5.8%	(5.5%)
2	VRR curve half way to vertical	143,011.6	4,467.3	3.1%	(3.0%)
3	Reduction in over forecasted peak load	143,653.5	3,825.4	2.7%	(2.6%)
4	Correction to overstated intermittent capacity	147,365.7	113.2	0.1%	(0.1%)
5	Zero demand resources	145,808.2	1,670.7	1.1%	(1.1%)
6	Zero EE offers and EE add back	139,810.6	7,668.3	5.5%	(5.2%)
7	Zero PRD offers	147,798.6	(319.7)	(0.2%)	0.2%
8	Zero seasonal offers	147,147.6	331.3	0.2%	(0.2%)
9	Matching seasonal offers only within LDAs	147,451.0	27.9	0.0%	(0.0%)
10	Zero capacity imports	147,472.5	6.4	0.0%	(0.0%)
11	Combined scenarios 4, 5, 6, 7, 8 and 10	135,524.0	11,954.9	8.8%	(8.1%)
12	Zero categorically exempt offers	145,773.2	1,705.7	1.2%	(1.2%)
13	All categorically exempt offers	145,162.6	2,316.3	1.6%	(1.6%)
14	All nuclear offers as price takers	147,466.3	12.6	0.0%	(0.0%)
15	Combined scenarios 2, 4, 5 and 10	142,653.2	4,825.7	3.4%	(3.3%)

Market Design Issues

There are significant market design issues in the capacity market that result in material differences between the prices that result from the existing design and prices that would result from a market design based on market fundamentals including a consistent definition of capacity.

Competitive Offers

Effective for the 2018/2019 and subsequent delivery years through the 2022/2023 BRA, the default offer cap for Capacity Performance Resources was 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 2023/2024 Delivery Year, the offer cap is the net avoidable cost (ACR) of a capacity resource.

[53] Scenario to Actual represents the impact of moving from the scenario to the actual BRA results and the percent change is *(Actual Cleared UCAP less Scenario Cleared UCAP) / (Scenario Cleared UCAP)*. The Actual to Scenario column represents the alternative perspective of the impact from moving from the actual BRA results to the scenario results and the percent change is *(Scenario Cleared UCAP less Actual Cleared UCAP) / (Actual Cleared UCAP)*.

Effective for the 2018/2019 and subsequent delivery years, the ACR definition was modified to include two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR). AFAE is defined to include avoidable expenses related to fuel availability and delivery. 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.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP).[54] This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. The Capacity Performance (CP) model was a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. Winter storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not work and does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions is complex and very difficult to administer, and includes

[54] See "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)," Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

subjective elements. The multiple complaints filed against PJM and the associated settlement are both further evidence of the unworkability of the CP design.[55]

Market Seller Offer Cap (MSOC)

In a September 2, 2021, Order in Docket Nos. EL19-47-000, EL19-64-000, ER21-2444-000, and ER21-2877-000, the Commission reestablished a market seller offer cap (MSOC) equal to the net avoidable cost rate (ACR) that had been in place from the introduction of RPM capacity market model through the introduction of the CP modification, replacing the Net CONE times B offer cap.[56] The Commission's modified MSOC rules were applied in the 2024/2025 BRA. The Commission's MSOC order was appealed and the appeal was denied.

Clearing Prices and Offer Caps

Net CONE times B was clearly well in excess of a competitive offer in the 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the clearing prices in the 2022/2023 BRA based on actual offers averaged less than half the level of the offer caps. But some generation owners did successfully exercise market power within this design. The change in the MSOC for the 2023/2024 BRA protected the market from noncompetitive outcomes.

Minimum Offer Price Rule (MOPR)

On June 29, 2018, the Commission initiated an FPA section 206 proceeding to address the price suppressive impact of resources receiving out of market support.[57] The Commission issued revised MOPR rules on December 19, 2019.[58] The rules approved in the December 19, 2019, order defined state subsidy and expanded the applicability of the MOPR to any new or existing resource that received a state subsidy, and retained the applicability of

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[55] *See* Offer of Settlement in the Winter Storm Elliott Complaints, Docket Nos. ER23-2975-000, EL23-53-000, et al. (September 29. 2023).

[56] 176 FERC ¶ 61,137 (September 2, 2021), *order on reh'g*, 178 FERC ¶ 61,121 (2022); *appeal denied*, Vistra Corp. v FERC, Case Nos 21-1214 et al (D.C. Cir August 15, 2023).

[57] 163 FERC ¶ 61,236 (2018) at 5 and 6.

[58] 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

MOPR to new gas-fired resources.[59] The Commission's resultant modified MOPR rules were applied in the 2022/2023 BRA.

On July 30, 2021, PJM filed tariff changes to effectively eliminate the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM defined it.[60] [61] [62] On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law based on a tie vote at the Commission and the rules governing tie votes.[63] This MOPR approach was applied to the 2024/2025 BRA. Appeals of PJM's revised MOPR rules are now pending before the U.S. Court of Appeals for the Third Circuit.[64]

The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate the MOPR while creating a

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59 OATT Attachment DD § 5.14(h).

60 *Revisions to Application of Minimum Offer Price Rule*, PJM Interconnection L.L.C., ER21-2582-000 (July 30, 2021).

61 *Protest of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-2592-000 (August 20, 2021).

62 *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Monitoring Analytics, LLC, ER21-2592-000 (September 22, 2021).

63 See Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (September 29, 2021); Notice of Denial of Rehearing Denied by Operation of Law, 177 FERC ¶ 62,105 (2021); *appeal pending*, PJM Power Providers Group v. FERC, Case Nos. 21-3068 et al. (3rd Cir.).

64 Case No. 23-3068.

confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[65]

CP Must Offer Requirement

Prior to the implementation of the capacity performance design, all capacity resources were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro and demand resources from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand side resources remains high. The failure to apply the must offer requirement consistently could also create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced. In the 2024/2025 BRA, 18,133.0 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,772.3 MW of intermittent and storage resources (3.9 percent of total cleared MW) were not offered in the 2024/2025 BRA. (See Table 7)

The sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,319.3 MW, or 49.3 percent of the required reserves and 33.3 percent of total reserves. The sum of cleared MW of DR is 8,083.9 MW, or 47.9 percent of required reserves and 32.4 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves.

Effective for the 2018/2019 and subsequent delivery years, all capacity resources are subject to the must offer requirement, with the exception of intermittent and storage resources which are categorically exempt from the must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent

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[65] See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources.

Avoidable Costs

Economics defines avoidable costs as costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. The exact dividing line between fixed costs and avoidable costs is established by the tariff as one year. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year. Conversely, but less intuitively, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate for one year, the delivery year. The two definitions produce identical results if applied correctly. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return.

The tariff also states that 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), despite the fact that these are not actually avoidable costs, particularly after the first year.

PJM arbitrarily modified the definition of avoidable costs effective April 15, 2019, to exclude major maintenance costs. [66] [67] [68] The result was to reduce gross ACR values includable in capacity market offers below actual gross ACR levels and to reduce offer caps in the capacity market below the competitive level. This change affected offer caps in the 2023/2024 and 2024/2025 BRAs.

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66 *PJM Interconnection L.L.C.,* Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery (February 14, 2019).

67 167 FERC ¶ 61,030 (April 15, 2019).

68 OATT Attachment DD § 6.8 (c).

Net Revenues

On December 22, 2021, in Docket Nos. EL19-58-006 and ER19-1486-003, the Commission issued an order on voluntary remand, reversing a prior finding that PJM's reserves market rules are unjust and unreasonable. As part of that order, the Commission also reversed its determination that PJM should use a forward looking energy and ancillary services (E&AS) revenue offset and directed PJM to submit a compliance filing restoring the tariff provisions defining the E&AS revenue offset based on historical net revenues.[69]

Constraints in RPM Markets: CETO/CETL and LDA Reliability Requirements

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.[70] 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 (UCAP), 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 local capacity emergency. The CETO reflects both the forecasted load of the LDA and the reliability profile of the generation resources projected to be available for the delivery year. PJM considers all existing generation, plus planned generation resources that have completed Interconnection Service Agreements (ISAs). The reliability requirement of the LDA is defined as the CETO plus the total projected internal generation capacity.

The second step in the process is to determine the transmission import limit for an LDA, called the Capacity Emergency Transfer Limit (CETL), which is also expressed in unforced megawatts. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the local 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 lower level of CETL,

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69 177 FERC ¶ 61,209 (2021); 179 FERC ¶ 61,104 (2022).

70 "PJM Manual 14B: PJM Region Transmission Planning Process," § C.2.1.2 Locational Deliverability Areas, Rev. 52 (Apr. 10, 2023). Manual 14B indicates that all "electrically cohesive load areas" are tested.

in combination with the internal LDA capacity resource supply curve, could result in larger locational price differences than if the CETL target were met.[71]

Under the Tariff, PJM determines, in advance of each BRA, whether specific Locational Deliverability Areas (LDAs) will be modeled in the auction, based on criteria which vary from clear to vague. PJM allows only modeled LDAs to price separate in an auction, regardless of the underlying fundamentals. 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.[72] 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."[73] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA.

The CETL levels and the CETL/CETO ratios directly affect but do not determine or predict whether there will be price separation for an LDA. Locational price differences result from the interaction between the CETL import limit, the demand for capacity in the LDA and the supply curve (MW and offer prices) 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 that met the demand for capacity in the LDA 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 there would be price separation if all the offers for internal capacity were high compared to offers for capacity outside the LDA.

The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. CETL is a critical parameter that can have and has had significant impacts on capacity market outcomes. The changes in CETL that have affected market outcomes in this and prior auctions have not been well explained. Absent a fully nodal capacity

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71 "PJM Manual 18: PJM Capacity Market," § 2.2 Role of Load Deliverability in the Reliability Pricing Model, Rev. 55 (Feb. 9, 2023).

72 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.

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

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 individual LDA supply curves and the transmission constraints between LDAs. The MMU recommends that PJM implement a nodal capacity market in order to ensure that transmission constraints and locational economic fundamentals are accurately reflected in capacity market prices.

The accuracy of the CETO calculation and reliability requirement of the LDA are based on the assumption that the planned generation capacity actually offers in the Base Residual Auction. Addition of a perfect generation resource with zero EFORD to an LDA would lower the CETO by the same magnitude as the unforced capacity of the perfect generation resource. The reliability requirement of the LDA would remain unchanged even if the planned resources did not offer. If the planned generation that PJM assumed would be available for the delivery year in the CETO calculation fails to offer in the Base Residual Auction, the resulting decrease in the CETO is less than the resulting decrease in the derated offered supply in the situation where the planned generation is a disproportionately large share of load or has different seasonal characteristics assumed in the class average ELCC derated value. The net effect is an increase in the reliability requirement of the LDA expressed in unforced capacity MW that does not reflect the actual supply and demand fundamentals in the LDA and artificially higher clearing prices.

This issue was highlighted in the clearing of the 2024/2025 Base Residual Auction. Substantial capacity in DPL South that PJM projected would be offered in the Base Residual Auction did not offer. Under the market rules in place at the time of the 2024/2025 BRA, PJM did not verify the reasonableness of its assumptions about the level of new entry. PJM delayed the calculation of the auction results while it addressed the issues of the inflated reliability requirement. PJM requested a waiver from FERC's 60 day prior notice to allow the proposed revisions to become effective one day after the date of its FPA section 205 filing, on December 24, 2022. In a February 21, 2023, Order in Docket Nos. ER23-729-000 and EL23-19-000, the Commission granted PJM's request for waiver of the FERC's 60-day prior notice requirement to allow an effective date of December 24, 2022, and accepted PJM's proposed tariff revisions to exclude Planned Generation Capacity Resources in the calculation of an LDA reliability requirement if the inclusion of those resources would increase the LDA reliability requirement by more than one percent and those resources do not participate in the relevant RPM auction.[74]

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[74] 182 FERC ¶ 61,109 (2023).

The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions.

ELCC/Capacity Value of Intermittent Resources

PJM has addressed the contribution of intermittent and storage resources to reliability in the PJM Capacity Market by using derating factors with the goal to ensuring that MW of capacity are comparable, regardless of the source. On July 30, 2021, FERC approved new PJM rules for defining/derating the capacity value of intermittent generators, based on PJM's interpretation of the effective load carrying capability (ELCC) method.[75] The 2023/2024 RPM Base Residual Auction was the first auction to use capacity values that resulted from PJM's application of an ELCC method.

The MMU opposed PJM's ELCC rules because they relied on significant counterfactual behavioral assumptions for storage and demand response resources, did not apply to all resource types, used invented (putative) data, used average technology values, were not locational, and provided for a long term guarantee of high average ELCC values for existing resources, among other issues.[76] [77] PJM's ELCC approach is an ex ante, administrative determination by PJM based on a black box model, of the capacity value of resources. The ELCC values are on a class average technology class basis with no recognition of locational differences and no opportunity to recognize actual performance in the delivery year. PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability.

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75 See 176 FERC ¶ 61,056.

76 See Comments and Motions of the Independent Market Monitor for PJM, Docket ER21-278-000, et al. (November 20, 2020); Answer, Motion for Leave to Answer, and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278-000 (December 14, 2020); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278-000 (December 18, 2020); Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278-000 (March 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278-000 (April 29, 2021).

77 See Comments of the Independent Market Monitor for PJM, Docket No. ER21-2043-000 (June 22, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2043-000 (July 9, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2043-000 (July 20, 2021).

PJM's approach to ELCC is based on correct insights about the need to calculate the availability of different resource types but the actual implementation results in a set of illogical implications. For example, PJM assigned penalties to solar resources during winter storm Elliott in December 2022 when solar resources did not generate power after dark.

Under the PJM ELCC approach a solar resource is assigned a derating factor, the derated MW are equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of "perfect" capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[78] As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of intermittent and storage resources. The MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[79]

Intermittent resources' correctly defined CIR values generally exceed the correctly defined level of capacity because the derated value (including derating based on ELCC) of capacity MW is based on energy deliveries in excess of the derated value. The derated ELCC values are generally based on energy deliveries equal to the full maximum output capability of the resource. The deliverable energy, required for capacity resource status, is based on CIRs. Derating factors, both the initial calculations and now based on ELCC type calculations, are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity that are asserted to be equivalent to resources that can produce for any of the 8,760 hours in a year. Both the capacity default

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78 "ELCC Class Ratings for 2024-2025 BRA," PJM Interconnection L.L.C. (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

79 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

derating factors applied to intermittent nameplate capacity prior to the 2023/2024 Delivery Year and the ELCC calculations effective with the 2023/2024 and 2024/2025 Delivery Years were based on the incorrect assumption that the intermittent resources provide reliable, deliverable output in excess of their CIRs. But that output, in excess of CIRs, is not deliverable when needed for reliability because it is in excess of the formally defined deliverability rights (CIRs) and therefore is not reliable output as assumed and therefore should not be included in the definition of intermittent capacity. Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource.[80]

PJM did a special study to recalculate the wind and solar ELCC class ratings for the 2023/2024 Delivery Year assuming the generation from an ELCC resource is capped at its CIR level.[81] The revised class rating for the 2023/2024 Delivery Year for onshore wind is 8.0 percent, 46.7 percent lower than the original class rating of 15.0 percent. The revised rating for fixed solar is 33.0 percent, 13.2 percent lower than the original class rating of 38.0 percent. The revised rating for tracking solar is 51.0 percent, 5.6 percent lower than the original class rating of 54.0 percent. PJM did not provide updated ELCC class ratings for the 2024/2025 Delivery Year to reflect generation capped at the CIR level.[82]

The definition of intermittent capacity used in the 2024/2025 BRA is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The issue will be corrected

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80 Updated rules beginning with the 2025/2026 Delivery Year require that ELCC accreditations exclude energy in excess of a generator's CIR. See 183 FERC ¶ 61,009 (April 7, 2023).

81 "Impact on Wind & Solar Class UCAP Values by Capping Hourly Outputs in UCAP Calculation at CIR Level," Item 4A in meeting notes for PC Special Session – CIRs for ELCC Resources, PJM Interconnection LLC, May 19, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

82 This recommendation has been adopted, including a complex transition process for those resources with understated CIRs. The new rules apply to Delivery Year 2025/2026 BRA and subsequent delivery years. *See* 183 FERC ¶ 61,009 (April 7, 2023). But PJM has failed to include this logic in the performance requirement for ELCC resources. PJM's energy market performance requirement for ELCC resources is set at the ELCC level rather than at the maximum facility output level that is the basis for CIRs and the basis for the ELCC rating. The performance obligation should be set equal to the CIR level because that is what PJM's reliability analysis assumes will be available to meet demand.

on a going forward basis beginning with the 2025/2026 Delivery Year.[83] But ELCC values based on the incorrect definition of deliverable energy were used for the 2023/2024 BRA and 2024/2025 BRA.[84] [85]

Seasonal Capacity

Effective for the 2018/2019 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources.[86] [87]

Summer period capacity performance resources may include summer period demand resources, summer period energy efficiency resources, capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during the summer peak hour periods consistently and measurably greater than their average expected energy output during winter peak hour periods.[88] This tariff language is vague and includes no actual metrics.

Winter period capacity performance resources may include capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during winter peak hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.[89]

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional

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83 183 FERC ¶ 61,009 (April 7, 2023).

84 PJM included all wind and solar units in the 2026 RTEP with an interconnection service agreement (ISA).

85 "CIRs for ELCC Resources: Cost Assessment of Potential Impacts to PJM Load Customers," Item 2, page 12 in meeting notes for PC Special Sessions – CIRs for ELCC Resources, PJM Interconnection, LLC, June 24, 2022 <https://pjm.com/committees-and-groups/committees/pc>.

86 158 FERC ¶ 62,220.

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

88 OATT Attachment DD § 5.5A(e)(i).

89 OATT Attachment DD § 5.5A(e)(ii).

CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year at a zero cost. Winter seasonal products 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. But this 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.

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

RPM rules allow for the matching of complementary seasonal products across LDAs. 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 regardless of physical or electrical proximity. Rules permitting market participants to aggregate resources in the same LDA became effective in the 2020/2021 Delivery Year. But the capacity performance rules permit aggregation across LDAs.[90] The capacity performance rules also permit capacity market sellers to offer standalone summer or winter resources and the auction clearing optimization matches and clears equal quantities of summer and winter resources from different sellers, also across LDAs.

The MMU recommends that the market rules not permit the matching of seasonal generation with demand resources. Demand resources are not the equivalent of generating resources.

Summer period capacity resources and winter period capacity resources located in the same LDA are cleared in equal quantities to satisfy the resource requirement of the LDA in which they are both located. The seasonal products that do not clear in the same LDA are then matched with complementary seasonal products located in the parent LDA. This could result in very different physical and electrical locations, for example for summer and winter resources located in distant LDAs that are both part of the rest of RTO LDA.

90 OATT Attachment DD § 5.12(a).

Regardless, during PAI, seasonal products are required to deliver in the LDA where they are physically located.

There is no reason to have such complex rules for combining seasonal products. PJM is a locational market. The current seasonal rules are not consistent with PJM's nodal and locational market design. Any combined seasonal products should be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated.

The seasonal matching rules increase uplift payments that may include the exercise of market power when seasonal products that offer at prices higher than the clearing price clear the auction when paired with complementary seasonal products from other LDAs.

For example, an offer for summer capacity in PSEG could 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, so the combined offer would receive the RTO clearing price. A winter resource in the PSEG LDA offered for $200 per MW-day that is matched with a summer resource in the DEOK LDA offered for $50 per MW-day would clear in the common parent LDA, rest of RTO, if the clearing price of the common parent LDA is greater than or equal to $125 per MW-day (the average of the two offers). The winter resource in the ComEd LDA would be paid uplift based on the difference between the clearing price and its standalone offer price, regardless of whether that offer was at a competitive level.

The current RPM market rules apply market power mitigation only to sell offers that would increase the market clearing price but do not address increases in uplift that result from complementary seasonal offers at greater than competitive levels. The RPM market rules permit the exercise of market power for market participants that receive seasonal uplift payments.

The MMU recommends that the RPM market power mitigation rules 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 in order to ensure that market power does not result in an increase in uplift payments for seasonal products.

Demand Side Resource Rules

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[91] 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 existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses 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, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Demand Resources (DR) are interruptible load resource that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. Effective with the 2020/2021 Delivery Year, the Capacity Performance product includes two possible season types, annual and summer. Annual Demand Resources are Demand Resources that are required to be available on any day during the delivery year for an unlimited number of interruptions, but are only required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer Period or Seasonal Demand Resources are Demand Resources that are 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, but are only required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.

Energy Efficiency Resource Rules

EE was first included in the capacity market in 2009, in the BRA for the 2012/2013 Delivery Year and in the incremental auctions for the 2011/2012 Delivery Year.[92] [93] EE was included

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91 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <https://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).

92 *2010 State of the Market Report for PJM, Volume 2,* Monitoring Analytics, LLC at 378 (March 10, 2011).

93 See PJM Interconnection, L.L.C., Letter Order in Docket No. ER10-366-000 (January 22, 2010).

in the capacity market solely based on the fact that PJM load forecasts used in the capacity market at the time did not fully reflect the impacts of EE on the demand for capacity for four years. EE was included in the capacity market based on the explicit rule that any specific EE resource would be removed from the capacity market after four years. Prior to the 2019/2020 Base Residual Auction, EE was 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 rationale for inclusion of EE as a supply side resource was entirely based on the assertion that EE would not be fully reflected in the PJM demand forecast for four years.

This lag in the inclusion of EE in the load forecast was resolved. PJM updated the peak load forecast method in 2015 to account for energy efficiency.[94] The 2019/2020 Base Residual Auction, run in May 2016, was the first BRA for which EE was reflected in the revised load forecast model without a lag.[95] But when the PJM forecast method changed so that the assumption underlying EE inclusion in the capacity market was no longer correct, PJM failed to take the logical step of removing EE from the capacity market. Instead, PJM implemented the EE addback adjustment through a change to the manuals rather than the tariff. Effective December 17, 2015, an EE addback mechanism and related changes were implemented.[96] The EE addback adjustment was intended to ensure that the continued inclusion of EE did not affect prices, but it did not work as intended. The issues with the addback mechanism have been resolved.[97] In addition, the EE addback adjustment does not affect the fact that customers continue to have to pay for EE through the capacity market despite the fact that by PJM's own logic, EE should not be in the capacity market and customers should not have to pay for it through the capacity market.

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94 See Revision History (Revision 29) in *PJM Manual 19: Load Forecasting and Analysis (December 5, 2019)*.

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

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

97 Based on an Issue Charge introduced by the MMU, PJM has updated the EE addback rules effective with the 2023/2024 Delivery Year, to address this issue. PJM updated the EE addback rules, such that starting from the 2023/2024 Base Residual Auction, the EE addback MW is iteratively adjusted until the difference between the EE addback and EE cleared is zero for all LDAs or as close to zero as possible. "PJM Manual 18: PJM Capacity Market," § 2.4.5 Adjustments to RPM Auction Parameters for EE Resources, Rev. 55 (Feb. 9, 2023).

PJM's continued inclusion of EE in the capacity market is inconsistent with the Reliability Assurance Agreement (RAA) which states that an Energy Efficiency Resource is a project "designed to achieve a continuous … reduction in electric energy consumption … that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention."[98]

The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's peak load forecasts now account for EE, and the rationale for inclusion no longer exists. EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets to the extent that it reduces energy and capacity use and therefore customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original reason for the inclusion of EE in the capacity market no longer exists. While EE does not affect the clearing price when the EE addback is done correctly, customers do pay for the cleared quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers.

External Generation Resources/Capacity Imports

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM 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). 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. 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.[99]

98 RAA Schedule 6 § L.1.

99 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[100] [101] [102]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[103] 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 subregional transmission organization granularity. Pseudo tied resources must also execute a pseudo tie reimbursement agreement that requires reimbursement of PJM's costs associated with performing studies and modifying its models or systems to establish and accommodate a pseudo tie.[104] [105]

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[100] See RAA Schedules 9 & 10.

[101] "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 55 (Feb. 9, 2023).

[102] "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 55 (Feb. 9, 2023).

[103] 161 FERC ¶ 61,197 (2017).

[104] Reimbursement Agreement for Pseudo-Ties <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/editable-reimbursement-agreement-for-pseudo-tie.ashx> (Accessed Oct 2, 2022).

[105] OATT Attachment MM § 18 includes forms of pseudo tie agreements.

Any party to these agreements has the right to terminate upon forty-two (42) months' notice prior to the commencement of a delivery year, subject to receiving all necessary regulatory approvals. PJM also has the right to terminate such agreements with sixty (60) days' notice for defined reasons including negative impacts on reliability.[106]

The energy from 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 Energy Market at a MW level equal to their ICAP.[107]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[108] [109] 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 requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[110] 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.[111]

CTRs

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by

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106 The conditions are defined at OATT Attachment MM § 18.

107 OATT Schedule 1 § 1.10.1A.

108 See RAA § 1.69A.

109 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 55 (Feb. 9, 2023).

110 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).

111 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).

capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of 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 transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[112] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the

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112 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 55 (Feb. 9, 2023).

clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

Market Clearing Model

The nested structure of the capacity market design 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 local LDA where the resource is located but is also eligible to satisfy the reliability requirement of all the higher level parent LDAs to which it belongs. For example, a resource located within the PSEG North LDA can satisfy the reliability requirement of PSEG North, of PSEG, of EMAAC, of MAAC and of the RTO. The problem arises because the LDA demand (VRR) curves are defined such that, in the optimization, any resource that satisfies the reliability requirement of a higher level LDA results in a larger consumer surplus than clearing that resource in a lower level LDA. The goal of the optimization is to maximize consumer surplus. 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 compared to clearing to meet PSEG North's requirement. As a result, the apparently optimal clearing solution would satisfy the parent LDA's requirement while clearing fewer resources to satisfy the child LDA's requirement. In order to ensure that the requirements of child LDAs are satisfied before the requirements of parent LDAs and therefore to ensure local reliability, the nesting based clearing process used by PJM requires iteratively solving a series of optimizations.[113] This clearing process always produces a solution with a lower consumer surplus by satisfying the child LDA's requirement before satisfying parent LDA's requirement. With this iterative solving, the clearing process may also result in implausible outcomes such as lower prices from a reduction in supply. 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.

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

PJM's market clearing algorithm does not include uplift payments in the objective function, resulting in a less accurate and less efficient result.[114] In RPM auctions, capacity market sellers are allowed to specify a minimum level of unforced capacity for any resource offered into the auction rather than a fully flexible offer. If any such inflexible offers are marginal or close to marginal, PJM's market solution algorithm relaxes the minimum level on those offers and reruns the optimization, allowing those offers to clear below the specified minimum level. Any resource that, as a result, cleared at a MW level below the specified minimum level, is paid uplift for the difference between the cleared MW and the minimum level, at the clearing price.

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 uplift 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.[115] The uplift payment for partially cleared resources equals the uplift 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.[116] [117]

The clearing optimization employed by PJM is not equipped to evaluate the tradeoff between selecting an inflexible segment and paying the associated uplift payment versus selecting an expensive flexible segment and not paying the uplift payment. This is because the solution method does not consider the additional cost of uplift payments as part of the objective function of the optimization. The alternative to clearing an inflexible offer will generally be clearing a higher priced offer to satisfy the applicable resource requirements without an uplift payment. In the MMU's approach, the market clearing algorithm explicitly compares solutions with uplift against solutions without uplift to arrive at the optimal solution. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function. Adoption of the additional MMU recommendation that all capacity offers be fully flexible, unless there is a physical reason for segments, would also significantly reduce or eliminate this problem.

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

115 OATT Attachment DD § 5.14(b).

116 OATT Attachment DD § 5.12(a).

117 For more details, see Attachment A.

MMU Review

The MMU reviewed inputs to and results of the 2024/2025 RPM Base Residual Auction:[118]

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

- Net Revenues. Calculated historic unit specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2019 through 2021;[119]

- 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, 2022, or reviewed requests for alternate maximum EFORds;

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

[118] 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 DR and EE. The EFORd values in this report are the EFORd values used in the 2024/2025 RPM Base Residual Auction.

[119] Net revenue values for the 2024/2025 RPM BRA were calculated consistent with the PJM market rules effective at the time. See 178 FERC ¶ 61,122 (2022).

- Clearing Prices. Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves; [120]

- 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.

Market Power Tests

All participants in the RTO, MAAC, EMAAC, DPL South, BGE, and DEOK markets failed the TPS test (Table 3).[121] 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. Market power mitigation was applied to 18 Capacity Performance sell offers. The MMU calculated unit specific ACR based offer caps for only 21 generation resources (2.2 percent) of the 964 generation capacity resources offered.[122]

The Commission's order effective September 2, 2021, required the use of offer caps equal to net ACR.[123] Market power mitigation was not applied to any Capacity Performance sell offers of generation capacity resources in the 2022/2023 or 2021/2022 RPM Base Residual Auctions as a result of the fact that the Net CONE times B offer cap applied in those auctions exceeded the competitive level. The purpose of market power mitigation is to produce competitive results despite the endemic structural market power in the capacity market. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes resulting in customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[124]

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

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

122 There were additional unit specific MSOC requests not included in these totals that were submitted and later withdrawn.

123 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022).

124 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual

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.[125] 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.

Table 3 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.[126] If the RSI_x is equal to 0.0, there is only one supplier and that supplier is a monopoly.

Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

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

126 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.

Table 3 RSI results: 2024/2025 RPM Base Residual Auction[127]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data for exports by 120 days prior to the 2024/2025 RPM Base Residual Auction.[128] Market power mitigation measures are applied to Existing Generation Capacity 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.[129]

Avoidable costs are the costs that a generation owner incurs as a result of operating the generating unit for one year, in particular the delivery year.[130] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not operate in the delivery year. 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 auctions for delivery

[127] The RSI shown is the lowest RSI in the market.

[128] 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).

[129] OATT Attachment DD § 6.5.

[130] OATT Attachment DD § 6.8(b).

years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[131]

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).[132] AFAE is defined to include avoidable expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

Effective for the 2022/2023 Delivery Year, the ACR definition excludes major maintenance costs if these costs had been previously included in unit specific ACR by a capacity market seller or effective with the 2020/2021 Delivery Year if these costs had not been previously included in unit specific ACR by a capacity market seller. [133] [134]

The opportunity cost option for exports allows capacity market sellers to provide 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 4, 964 generation resources submitted Capacity Performance offers in the 2024/2025 RPM Base Residual Auction. Of the 964 offers, 97.8 percent were based on default ACR, were price takers, or were uncapped planned resources. Only 2.3 percent of offers requested unit specific review, of which 2.2 percent were for unit specific ACR review and 0.1 percent were for unit specific opportunity cost review. Only a very small proportion of that 2.2 percent did not reach agreement with the MMU. The MMU calculated offer caps for 742 generation resources that submitted capacity offers. Unit specific ACR based offer caps were calculated for 21 generation resources (2.2 percent), of which only six resources (0.6 percent) requested a CPQR. Of the 964 generation capacity resources offered, 715 generation resources (74.2 percent) had default ACR based offer caps, 21 generation resources (2.2 percent) had unit specific ACR based offer caps, one generation resource (0.1 percent) had an opportunity cost based offer cap, 17 Planned

131 OATT Attachment DD § 6.8(a).

132 151 FERC ¶ 61,208.

133 167 FERC ¶ 61,030 (April 15, 2019).

134 OATT Attachment DD § 6.8 (c).

Generation Capacity Resources (17.1 percent) had uncapped offers, five generation resources (0.5 percent) had uncapped planned uprates plus default ACR based offer caps for the existing portion of the units, zero generation resources had uncapped planned uprates plus price taker status for the existing portion of the units, while the remaining 205 generation resources (21.3 percent) were price takers.

Market power mitigation measures are applied to capacity resources subject to MOPR 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 5, there were unit specific exception requests for 471.8 MW for MOPR under OATT Attachment DD § 5.14(h-2). Of the 1,288.0 MW offered that were subject to MOPR, 123.0 MW cleared and 1,041.0 MW did not clear.

On September 29, 2021, PJM's proposed MOPR changes took effect by operation of law.[135] The MOPR changes modified the MOPR applicability rules and replaced it with an effectively meaningless MOPR screen.[136] The only reason that any capacity resources were subject to MOPR review in the 2024/2025 BRA was that the resources missed the MOPR certification deadline.[137]

135 See Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582-000 (September 29, 2021); Notice of Denial of Rehearing Denied by Operation of Law, 177 FERC ¶ 62,105 (2021); *appeal pending*, PJM Power Providers Group v. FERC, Case Nos. 21-3068 et al. (3rd Cir.).

136 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

137 See OATT Attachment DD § 5.14(h-2).

Tables for Offer Caps and Offer Floors

Table 4 ACR statistics: 2024/2025 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	715	74.2%
Unit specific ACR (APIR)	14	1.5%
Unit specific ACR (APIR and CPQR)	6	0.6%
Unit specific ACR (non-APIR)	1	0.1%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost	1	0.1%
Default ACR and opportunity cost	0	0.0%
Net CONE times B	NA	NA
Uncapped planned uprates and default ACR	5	0.5%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA
Uncapped planned uprates and price taker	0	0.0%
Uncapped planned generation resources	17	1.8%
Existing generation resources as price takers	205	21.3%
Total Generation Capacity Resources offered	964	100.0%

Table 5 MOPR statistics: 2024/2025 RPM Base Residual Auction

			ICAP (MW)			UCAP (MW)	
MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	4	471.8	267.0	123.0	123.0	123.0
OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	1,213.0	1,165.0	1,041.0
Total		4	471.8	267.0	1,336.0	1,288.0	1,164.0

Generation Capacity Resource Changes

As shown in Table 4, Capacity Performance offers were submitted for 964 generation resources in the 2024/2025 RPM Base Residual Auction, compared to 1,003 generation resources offered in the 2023/2024 RPM Base Residual Auction, a net decrease of 39 generation resources. This was a result of 73 fewer generation resources offered offset by 34 additional generation resources offered.

The 34 additional generation resources offered consisted of 28 resources that were unoffered in the 2023/2024 BRA (800.3 MW), five new resources (328.5 MW), and one resource that was previously entirely FRR committed (12.4 MW).[138]

The five new Generation Capacity Resources consisted of five solar resources (328.5 MW).

[138] Unless otherwise specified, all volumes and prices are in terms of UCAP.

The 73 fewer generation resources offered consisted of 56 intermittent resources and capacity storage resources not offered (389.8 MW), eight additional resources fully committed to FRR (648.8 MW), seven deactivated resources (1,333.1 MW), and two resources not offered for other reasons (resources excused from offering for reasons other than retirement or proposed generation capacity resources not offered) (13.2 MW). Table 6 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2023/2024 BRA and the 2024/2025 BRA.

Table 6 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
MORGANTOWN CT 1	Pepco	16.0	12-Apr-22	01-Oct-22
MORGANTOWN CT 2	Pepco	16.0	12-Apr-22	01-Oct-22
VINELAND CT	EMAAC	21.1	06-Jul-22	14-Oct-22
DICKERSON CT 1	Pepco	18.0	25-Jul-22	23-Oct-22
JOLIET COAL 6	ComEd	281.0	25-Jul-22	01-Jun-23
JOLIET COAL 7	ComEd	550.0	25-Jul-22	01-Jun-23
JOLIET COAL 8	ComEd	550.0	25-Jul-22	01-Jun-23
Total		1,452.1		

RTO Market Results

Total Offers

Table 7 shows total RTO offer data for the 2024/2025 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[139] [140] As shown in Table 7, total internal RTO unforced capacity (UCAP), excluding generation winter capacity, increased 2,381.1 MW (1.2 percent) from 198,498.2 MW in the 2023/2024 RPM BRA to 200,879.3 MW.[141]

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

139 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.

140 Maps of the LDAs can be found in the *2019 Annual State of the Market Report for PJM*, Appendix A, PJM Overview, Figure A-3, Figure A-4, and Figure A-5.

141 The reported internal capacity includes FRR capacity.

internal capacity change attributable to EFORd changes and not capacity modifications. As shown in Table 9, the 2,381.1 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (1,017.9 MW), net DR capacity changes (-698.7 MW), net EE modifications (3,166.2 MW), the EFORd effect due to higher sell offer EFORds (-1,090.9 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-13.4 MW).[142]

As shown in Table 11, total internal RTO unforced winter seasonal capacity for November through April increased 62.8 MW from 1,933.9 MW in the 2023/2024 BRA to 1,996.7 MW in the 2024/2025 BRA. The 62.8 MW increase in winter seasonal capacity was a result of net generation winter capacity modifications.

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 2024/2025 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the RAA and associated manuals.[143] 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.[144] 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

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142 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 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 2023/2024 BRA, this conversion factor was 1.0901. For the 2024/2025 BRA, this conversion factor was 1.0894. 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 RAA Schedule 6, Section B. See also "PJM Manual 20: PJM Resource Adequacy Analysis," § 1.3 Parameters Reviewed in the Stakeholder Process, Rev. 12 (Aug. 25, 2021).

143 See RAA Schedule 9.

144 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 2.1 Net Capability - General, Rev. 16 (Aug. 1, 2021). The manual states "the end of the next Delivery Year."

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 (990.1 MW), for FRR committed resources (32,379.9 MW) and for imports (1,527.1 MW), total RPM capacity was 171,016.6 MW compared to 169,159.9 MW in the 2023/2024 RPM Base Residual Auction.[145] Generation winter capacity increased by 28.5 MW, FRR volumes increased by 551.9 MW, and imports decreased by 0.9 MW from the 2023/2024 RPM Base Residual Auction.[146]

Of the 1,527.1 MW of imports, 0.0 MW were committed to an FRR capacity plan and 1,527.1 MW were offered in the auction, of which 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.

RPM capacity was reduced by exports of 2,500.4 MW, a decrease of 17.5 MW from the 2023/2024 RPM Base Residual Auction. Of total exports, 1,544.2 MW (61.8 percent) were to MISO, 674.0 MW (27.0 percent) were to NYISO, 95.0 MW (3.8 percent) were to Duke Energy Carolinas, and 187.2 MW (7.5 percent) were to Louisville Gas and Electric Company (LG&E)/Kentucky Utilities Company (KU).

RPM capacity was also reduced by 921.9 MW of FRR optional volumes not offered and by 3,583.0 MW which were excused from the RPM must offer requirement.[147] FRR optional volumes decreased by 156.6 MW and excused Existing Generation Capacity Resources increased by 943.6 MW from the 2023/2024 RPM Base Residual Auction. The

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145 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.

146 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.

147 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 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.

excused Existing Generation Capacity Resources were the result of plans for retirement, changes in capacity resource status, and grandfathered external obligations.[148]

In addition, RPM capacity was reduced by 149.9 MW of Planned Generation Capacity Resources which were not subject to the must offer requirement, by 3,872.0 MW of intermittent resources and 1,305.8 MW of capacity storage resources which were not subject to the must offer requirement, by 594.5 MW of unoffered generation winter capacity, and by 1,567.7 MW of unoffered DR and EE which were not subject to the must offer requirement.[149] Unoffered Planned Generation Capacity Resources increased by 0.9 MW, unoffered intermittent resources increased by 151.1 MW, unoffered capacity storage resources increased by 254.5 MW, unoffered generation winter capacity increased by 58.3 MW, and unoffered DR and EE increased by 145.3 MW from the 2023/2024 RPM Base Residual Auction.

Subtracting excused and unoffered capacity resulted in 156,521.4 MW that were available to be offered in the RPM Auction, an increase of 477.4 MW from the 2023/2024 RPM Base Residual Auction. After accounting for these factors, 0.0 MW were not offered and unexcused in the RPM Auction.

Offered MW increased 477.4 MW from 156,044.0 MW to 156,521.4 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, increased 235.3 MW from 131,820.4 MW in the 2023/2024 RPM Base Residual Auction to 132,055.7 MW.[150] 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

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

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

150 Unless otherwise specified, an annual equivalent MW quantity is used to report seasonal capacity, which is calculated as the MW times the ratio of the number of days in the seasonal period to the number of days in the delivery year. The offered capacity in this report differs from the PJM reported numbers due to seasonal versus annual equivalent MW reporting for seasonal offers, and the classification of and UCAP conversion for the underlying resources in aggregate resources.

reliability.[151] The 235.3 MW increase in the RTO Reliability Requirement adjusted for FRR obligations from the 2023/2024 RPM Base Residual Auction was a result of a 941.4 MW increase in the RTO Reliability Requirement not adjusted for FRR offset by a 706.1 MW increase in the FRR obligation, shifting the RTO market demand curve to the right. The forecast peak load expressed in terms of installed capacity increased 960.3 MW from the 2023/2024 RPM Base Residual Auction to 150,640.3 MW. The 941.4 MW increase in the RTO Reliability Requirement was a result of a 1,046.8 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2023/2024 level offset by a 105.4 MW decrease attributable to the change in the FPR. The decrease in the FPR from the 2023/2024 RPM Base Residual Auction was a result of a decrease in the IRM offset by a decrease in the pool wide average EFORd.

Table 12 shows the installed and offered generation capacity for the top five owners. The total installed capacity (193,237.2 ICAP MW) includes all Generation Capacity Resources that qualified as PJM Capacity Resources for the 2024/2025 RPM Base Residual Auction (190,630.0 ICAP MW), annual equivalent MW quantity for generation winter capacity (990.1 ICAP MW), and external resources offered or committed to an FRR plan (1,617.1 ICAP MW).

Clearing Prices

Table 14 shows the clearing prices for 2023/2024 BRA and 2024/2025 BRA. The clearing price for the RTO decreased by $5.21 or 18.0 percent from $34.13 in the 2023/2024 BRA to $28.92 in the 2024/2025 BRA. The lower clearing prices in 2024/2025 BRA were primarily the result of lower offer prices. Competitive capacity market offers reflect, regardless of tariff requirements, participants' forward looking expectations of profits from the energy market and therefore the revenue they require from the capacity market.

The Commission required the use of historical net revenues in calculating offer caps for the 2023/2024 BRA and 2024/2025 BRA while forward net revenues were used for the 2022/2023 BRA. The net revenues were not relevant for most units for the 2022/2023 BRA because the inflated offer caps in that auction were based on Net CONE times B.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 24 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day. Overall, total offers greater than $35 per MW-day declined 38.3 percent, from 18,293.1 MW in the 2023/2024 BRA to 13,227.9 MW in the 2024/2025 BRA. Offers for DR were 16.3 percent of the offers greater than $35.00 per MW-day compared to 13.3 percent in the 2023/2024 RPM Base Residual Auction. Offers for coal

151 RAA Schedule 4.1.

fired units made up 35.8 percent of the offers greater than $35.00 per MW-day compared to 50.9 percent in the 2023/2024 RPM Base Residual Auction. Offers for combustion turbine units made up 21.2 percent of the offers greater than $35.00 per MW-day compared to 15.5 percent in the 2023/2024 RPM Base Residual Auction.

Demand Side Resources

Table 31 shows offered and cleared capacity from DR and EE in the 2024/2025 RPM Base Residual Auction compared to the 2023/2024 RPM Base Residual Auction. Offers for DR increased from 10,135.7 MW in the 2023/2024 BRA to 10,136.6 MW in the 2024/2025 BRA, an increase of 0.9 MW or 0.0 percent. Offers for EE increased from 5,346.8 MW in the 2023/2024 BRA to 8,002.0 MW in the 2024/2025 BRA, an increase of 2,655.2 MW or 49.7 percent.

Capacity Imports

Table 37 shows the MW quantity of imports offered and cleared in the 2007/2008 through 2024/2025 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 and prior to the implementation of the pseudo tie rules. Of the 1,527.1 MW of imports offered in the 2024/2025 RPM BRA, 1,397.6 MW (91.5 percent) cleared.

CETO/CETL Values

Table 25 shows the CETL and CETO values used in the 2024/2025 study compared to the 2023/2024 values. The CETL value for the ComEd LDA decreased significantly. PJM did not provide any reason for the change in the CETL value for the ComEd LDA from the 2023/2024 BRA.[152]

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 some 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

152 See the PJM "2024/2025 RPM Base Residual Auction Planning Period Parameters," (February 27, 2023) <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-planning-period-parameters-for-base-residual-auction-pdf.ashx>.

approved and confirmed by all relevant entities are included in the CETL cases.[153] The MMU recommends that CETL be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. Any other assumption overstates the amount of capacity supply and suppresses market prices for PJM capacity resources. The external capacity that does not have a must offer requirement in the PJM Capacity Market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to derive CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

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.

There were five locationally binding constraints in the 2024/2025 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.[154]

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 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.

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153 See "PJM Manual 14B: PJM Region Transmission Planning Process," § C.3.1.3 General Procedures and Assumptions, Rev. 52 (Apr. 10, 2023).

154 For more details on the clearing algorithm, see Attachment A.

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.[155] [156] As shown in Table 13, the preliminary net load price is $28.99 per MW-day in the RTO. For example, the adjusted preliminary zonal capacity price of BGE was higher than the preliminary zonal capacity price due to the adjustment to cover the funding for PRD credits.

As shown in Table 15 and Table 16, the 139,810.2 MW of cleared generation and DR for the entire RTO, resulted in a reserve margin of 21.7 percent and a net excess of 8,086.8 MW over the reliability requirement adjusted for FRR and PRD of 131,723.4 MW (Installed Reserve Margin (IRM) of 14.7 percent).[157] [158] [159] [160] Net excess increased 251.5 MW from the net excess of 7,835.3 MW in the 2023/2024 RPM Base Residual Auction. As shown in Figure

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

156 In the Base Residual Auction, PJM models PRD on the supply side. The cleared PRD is credited with the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs. The net load price reflects these adjustments to cover the funding of PRD credits.

157 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity 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 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 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 less the reliability requirement. MW that clear but require uplift payments are not included in PJM's definition of cleared capacity and therefore excess capacity. Those MW should be included in the definition of cleared capacity and therefore excess capacity.

158 The IRM decreased from 14.8 percent in the 2023/2024 RPM Base Residual Auction to 14.7 percent in the 2024/2025 RPM Base Residual Auction.

159 The 21.7 percent reserve margin does not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. The 21.7 percent reserve margin also does not include the 26.7 MW of uplift. This is how PJM calculates the reserve margin.

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

2, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $28.92 per MW-day.

The actual market results in the 2024/2025 BRA did include uplift MW and payments resulting from inflexibly offered partially cleared resources. PJM does not include the uplift MW in the reported cleared capacity and therefore does not include uplift MW in the calculation of reserves and excess reserves. Uplift MW are cleared MW with the same capacity status as all other cleared capacity MW and therefore should be included in reported cleared capacity and in the calculation of reserves and excess reserves.

Uplift MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[161] [162] 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 awarded an uplift payment.[163] The market results in the 2024/2025 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

The market results in the 2024/2025 BRA did not include seasonal uplift MW and payments. Under the seasonal capacity rules, the optimization considers the average cost of clearing seasonal offers, including an offer in each season. This can result in clearing seasonal sell offers for the higher cost season at offer prices that are not competitive and making seasonal uplift payments based on those high offer prices.

Table 17 shows offered and cleared MW by LDA, resource type, and season in the 2024/2025 RPM Base Residual Auction. Of the 138,382.7 MW of generation offers, 137,649.8 MW were for the annual season. Of the 10,136.6 MW of DR offers, 9,942.8 MW were for the annual season. Of the 8,002.0 MW of EE offers, 7,580.1 MW were for the annual season.

Table 18 shows the weighted average sell offer prices by LDA, resource type, and season. For generation, the weighted average sell offer prices for generation in RTO for annual were greater than the weighted average sell offer prices for winter, which 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

161 OATT Attachment DD § 5.14(c)(2).

162 OATT Attachment DD § 6.8(a).

163 OATT Attachment DD § 5.14(c)(2)(ii).

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 from offer cap market power mitigation.

Table 19 shows the offered generation capacity MW by season and price range relative to the applicable market seller offer caps (MSOCs) in the 2024/2025 RPM Base Residual Auction. Of the 138,382.7 MW of generation offers, 59,438.7 MW (43.0 percent) were offered below the applicable MSOC, 78,944.0 MW (57.0 percent) were offered at the applicable MSOC, and 0.0 MW (0.0 percent) were offered greater than the applicable MSOC.

Table 20 shows the weighted average sell offer prices and market seller offer caps for existing generation capacity resources in the entire RTO. The weighted average sell offer for existing generation capacity resources ($9.30 per MW-day) was less than half the weighted average market seller offer cap ($29.90 per MW-day).

Table 21 shows cleared MW by zone and fuel source. Of the 138,382.7 MW offered for generation resources, 132,007.7 MW cleared (95.4 percent). Of the 147,478.9 cleared MW in the entire RTO, 25,156.1 MW (17.1 percent) cleared in ComEd, followed by 19,865.1 MW (13.5 percent) in AEP and 14,184.9 MW (9.6 percent) in PPL. Of the 132,007.7 cleared MW for generation resources in the entire RTO, 71,460.8 MW (54.1 percent) were gas resources, followed by 25,817.9 MW (19.6 percent) from nuclear resources and 23,079.8 MW (17.5 percent) from coal resources. Cleared MW from coal resources increased 2,178.5 MW from the 2023/2024 RPM Base Residual Auction while cleared MW from gas resources decreased 1,456.1 MW from the 2023/2024 RPM Base Residual Auction.

The 9,015.8 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 9,015.8 uncleared MW in the entire RTO, 521.2 MW were EE offers, 2,146.2 MW were DR offers, and the remaining 6,348.4 MW were generation offers.[164] Table 22 presents details on the generation offers that did not clear. Of the 6,348.4 MW of uncleared generation offers, 3,861.6 MW (60.8 percent) were for generation resources greater than 40 years old, and 2,486.8 MW (39.2 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 2024/2025 BRA. Of the 72 generation resources that did not clear 6,348.4 MW in the 2024/2025 BRA, 37 of those generation

164 Reported uncleared MW values are based on rounded annual equivalent MW values for seasonal offers.

resources did not clear 5,390.0 MW in RPM Auctions for the 2023/2024 Delivery Year. Of those 37 generation resources that did not clear MW in RPM Auctions for the 2024/2025 and 2023/2024 Delivery Years, 24 of those generation resources did not clear 1,070.4 MW in RPM Auctions for the 2022/2023 Delivery Year. Thus, 5,390.0 MW of capacity did not clear in two sequential auctions, but 1,070.4 MW did not clear in three sequential auctions.

CTRs

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays 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. For LDAs in which the RPM auctions for a delivery year resulted in a positive locational price adder, an LSE with load in the LDA is entitled to a payment equal to the locational price adder multiplied by the MW of the LSEs' CTRs.[165] [166] The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of 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 transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.[167]

In the 2024/2025 RPM Base Residual Auction, BGE had 4,513.2 MW of CTRs with a total value of $38,728,614 and DPL had 544.7 MW of CTRs with a total value of $120,535. EMAAC, excluding DPL, had 3,704.1 MW of CTRs with a total value of $7,381,909 and DEOK had 3,015.4 MW of CTRs with a total value of $74,093,944.

MAAC had 1,026.2 MW of customer funded ICTRs with a total value of $7,704,472, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $79,716, BGE had

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165 The locational price adder for a child LDA is the difference between the resource clearing price in the child LDA and the resource clearing price in the corresponding parent LDA.

166 But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs.

167 Incremental Rights-Eligible Required Transmission Enhancements are regional facilities and necessary lower voltage facilities or lower voltage facilities where cost responsibility is assigned to non-contiguous transmission zones that are not directly electrically connected, or cost responsibility is assigned to merchant transmission providers that are responsible customers (PJM Manual 18, Section 6.1).

65.7 MW of customer funded ICTRs with a total value of $563,782, and DEOK had 155.0 MW of customer funded ICTRs with a total value of $3,808,629.

MAAC had 486.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,651,831, EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $1,889,269 and BGE had 306.0 MW with a value of $2,625,832.

Analysis of Market Results

The MMU analyzed the impacts of specific market design features, definitions of capacity, and market behavior. The market design features analyzed are: the shape of the VRR curve; and forecast error. The definitions of capacity analyzed are: intermittent resources; DR; EE; PRD; seasonal products; and imports. The market behaviors analyzed are: offers by resources categorically exempt from the must offer obligation; and offers by nuclear plants.

Impact of Market Design Issues

The MMU analyzed the impact of specific, significant market design issues, including: the impact of the shape of the demand (VRR) curve; and the impact of the load forecast.

Impact of Vertical VRR Curve (Scenario 1)

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the MW equal to the reliability requirement. The downward sloping segment begins at the MW level that is 1.05 percent less than the reliability requirement.[168] Figure 1 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2024/2025 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate, although the basis for the asserted value was not clearly defined based on market fundamentals.[169]

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168 The formula for the MW level where the VRR curve begins the downward slope is given by *Reliability Requirement x [(100% + IRM – 1.2%) / (100% + IRM)]*.

169 See 117 FERC ¶ 61,331 (2006).

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[170] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99.0 percent to 101.7 percent of the reliability requirement.[171] The second downward sloping segment is from 101.7 percent to 106.8 percent of the reliability requirement (Figure 1).

PJM's required demand for capacity, based on reliability requirements, includes expected peak load plus a required reserve margin, but most points on the downward sloping part of the demand curve, the (VRR curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and substantially higher payments by customers. The required demand for capacity defines a vertical demand curve equal to expected peak load plus a required reserve margin.

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 set equal to the reliability requirement.

Table 26 shows the results if PJM had used a vertical demand curve set equal to the reliability requirement for the RTO and for each modeled LDA in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the DEOK import limit and the BGE

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170 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

171 The reported VRR parameters are rounded to first decimal place, e.g. 98.95 percent is rounded to 99.0 percent.

import limit. The RTO clearing price would have decreased to $20.00 per MW-day, and the clearing quantity would have decreased to 139,392.1 MW. The clearing quantity of seasonal capacity would have would have remained the same at 605.6 MW. The MAAC clearing price would have decreased to $35.00 per MW-day, and the clearing quantity would have decreased to 60,614.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have decreased to $20.00 per MW-day, and the clearing quantity would have decreased to 1,860.4 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $36.90 per MW-day, and the clearing quantity would have decreased to 28,689.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have decreased to $54.81 per MW-day, and the clearing quantity would have decreased to 1,276.6 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have decreased to $35.00 per MW-day, and the clearing quantity would have decreased to 2,325.0 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If PJM had used a vertical demand curve set equal to the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,377,668,211, a decrease of $815,160,040, or 37.2 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 59.2 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

Impact of VRR Curve Half Way to Vertical (Scenario 2)

In the 2022 Quadrennial Review, as a transition to a vertical demand curve, the MMU proposed to change the parameters of the VRR curve to reduce the procurement of excess capacity above the reliability requirement. For the MMU's proposed VRR curve, the maximum price on the VRR curve is set at the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is set from 99 percent to 100.8 percent of the reliability requirement. The second downward sloping segment is set from 100.8 percent to 103.4 percent of the reliability requirement. The MMU's proposed VRR curve falls half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement.

The actual flatter downward sloping shape of the VRR curve used by PJM had a significant impact on the outcome of the auction. As a result of the flatter downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a steeper demand curve set at half way between the VRR curve used in the 2024/2025 BRA and the reliability requirement.

Table 27 shows the results if PJM had used a VRR curve set at half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement for RTO and for each modeled LDA in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the EMAAC import limit. The RTO clearing price would have decreased to $22.50 per MW-day, and the clearing quantity would have decreased to 143,011.6 MW. The clearing quantity of seasonal capacity would have would have remained the same at 605.6 MW. The MAAC clearing price would have decreased to $43.00 per MW-day, and the clearing quantity would have decreased to 62,431.2 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have decreased to $31.75 per MW-day, and the clearing quantity would have decreased to 1,969.1 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $43.00 per MW-day, and the clearing quantity would have decreased to 29,836.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have decreased to 1,349.3 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $85.00 per MW-day, and the clearing quantity would have decreased to 2,483.2 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If PJM had used a VRR curve set at half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,712,525,223, a decrease of $480,303,029, or 21.9 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 28.0 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a VRR curve set at half way between the VRR curve used in the 2024/2025 RPM Base Residual Auction and the reliability requirement.

Impact of the Reduction in Over Forecasted Peak Load (Scenario 3)

The accuracy of the peak load forecast had a significant impact on auction results. Table 28 summarizes the peak load forecasts for the 2019/202020 through 2023/2024 Delivery Years. 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 in the delivery year. Analysis of the RPM auctions for the five delivery years from 2019/2020 through 2023/2024 shows that the peak load forecast for the Third Incremental Auction has been on average 2.0 percent lower than the peak load forecast for the corresponding Base Residual Auction.

Table 29 shows the results if the peak load forecast had been 2.0 percent lower in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have decreased to $23.00 per MW-day, and the clearing quantity would have decreased to 143,653.5 MW. The amount of cleared seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have decreased to $44.00 per MW-day, and the clearing quantity would have decreased to 62,892.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have decreased to $51.73 per MW-day, and the clearing quantity would have decreased to 2,012.5 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $44.90 per MW-day, and the clearing quantity would have decreased to 29,979.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $132.40 per MW-day, and the clearing quantity would have decreased to 1,324.9 MW. The clearing quantity for seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $85.00 per MW-day, and the clearing quantity would have decreased to 2,488.4 MW. The clearing quantity for seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the peak load forecast for the 2024/2025 RPM Base Residual Auction had been 2.0 percent lower and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,800,931,369, a decrease of $391,896,882, or 17.9 percent, compared to the actual results. From another perspective, using PJM's peak load forecast for the 2024/2025 Base Residual Auction resulted in a 21.8 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what revenues would have been using a load forecast that is 2.0 percent below the PJM peak load forecast. (Scenario 3)

Impact of Definition of Capacity Issues

The MMU analyzed the impact of specific, significant issues related to the definition of capacity, including: the impact of overstated intermittent capacity; the impact of demand side resources; the impact of EE; the impact of PRD; the impact of seasonal capacity; the impact of seasonal capacity matching across LDAs; and the impact of external capacity resources.

Impact of Correction to Overstated Intermittent Capacity (Scenario 4)

Overstatement of the reliability contribution of intermittent resources can have a significant impact on capacity market results.[172] The PJM method for computing derated capacity values, applicable to delivery years prior to 2023/2024, and PJM's approach to the ELCC method, used to determine capacity values for 2023/2024 and 2024/2025, incorrectly included generation in excess of the CIR levels for wind and solar generators. PJM filed and the Commission accepted new rules to correct this issue on April 7, 2023, but the old, incorrect rules that overstated ELCC derated values by incorrectly including generation in excess of CIRs, were not modified and the overstated ELCC class ratings were used for the 2024/2025 RPM Base Residual Auction.[173]

The MMU has previously found that the derating method used through the 2022/2023 Delivery Year, prior to the implementation of PJM's ELCC approach, overstated the capacity value of solar and wind units due to the inclusion of generation in excess of CIRs.[174] Based on an analysis of data from 2019 through 2021, the capacity value of solar units would have been 20.0 percent lower and the summer and annual capacity of wind units would have been 48.9 percent lower had the generation been capped at the CIR level.

Table 30 shows the auction results if the reliability contribution of solar and wind resources were reduced to remove the generation in excess of the CIRs in the ELCC class rating calculation. The MW values associated with all offers from solar resource were

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172 There were no offers for battery resources in the 2024/2025 RPM Base Residual Auction. Beginning with the 2023/2024 Delivery Year, capacity value for batteries is determined by PJM's ELCC analysis.

173 183 FERC ¶ 61,009 (April 7, 2023).

174 See page 8 in "Intermittent Output and CIRs," IMM, PC Special Session – CIRs for ELCC Resources (February 23, 2022) <https://pjm.com/committees-and-groups/committees/pc>.

reduced by 20.0 percent. The MW values associated with annual and summer offers from wind resources were reduced by 48.9 percent.[175] All binding constraints would have remained binding. The RTO clearing price would have increased to $31.22 per MW-day, and the clearing quantity would have decreased to 147,365.7 MW. The clearing quantity of seasonal capacity would have decreased to 297.8 MW. The MAAC clearing price would have remained the same at 49.49 per MW-day, and the clearing quantity would have decreased to 64,156.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 20.2 MW. The DEOK clearing price would have increased to $106.48 per MW-day, and the clearing quantity would have decreased to 2,042.7 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $55.00 per MW-day, and the clearing quantity would have decreased to 30,670.1 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $101.78 per MW-day, and the clearing quantity would have decreased to 1,413.5 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the overstated unforced capacity of solar resources offered in the 2024/2025 RPM Base Residual Auction had been reduced by 20 percent and the annual and winter unforced capacity of wind resources offered had been reduced by 48.9 percent and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,272,074,858, an increase of $79,246,607, or 3.6 percent, compared to the actual results. From another perspective, the inclusion of all overstated offers from solar and wind resources resulted in a 3.5 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if overstated offers from solar resources had been reduced by 20 percent and annual and summer offers from wind resources had been reduced by 48.9 percent.

Impact of Zero Demand Resources (Scenario 5)

The inclusion of all sell offers for demand resources, including annual and seasonal, had a significant impact on the auction results. Table 32 shows the results if there were no

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175 There were no offers for battery resources in the 2024/2025 RPM Base Residual Auction.

offers for DR in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the MAAC and the DPL South import limits. The RTO clearing price would have increased to $92.77 per MW-day, and the clearing quantity would have decreased to 145,808.2 MW. The clearing quantity of seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have increased to $92.77 per MW-day, and the clearing quantity would have increased to 5,102.4 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have increased to $113.38 per MW-day, and the clearing quantity would have decreased to 1,866.4 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $118.12 per MW-day, and the clearing quantity would have decreased to 30,199.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $118.12 per MW-day, and the clearing quantity would have decreased to 1,402.5 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $112.14 per MW-day, and the clearing quantity would have decreased to 2,585.9 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for DR in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $5,248,970,191, an increase of $3,056,141,939, or 139.4 percent, compared to the actual results. From another perspective, the inclusion of DR resulted in a 58.2 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without any DR.

Impact of Zero EE Offers and EE Add Back (Scenario 6)

The inclusion of sell offers for EE, with the EE addback mechanism, had a significant impact on the auction results, but not on the auction clearing prices. The 2024/2025 RPM Base Residual Auction was the fifth BRA that included EE and the EE addback mechanism. RPM rules allow EE to participate on the supply side. An adjustment is made to the demand curve through the EE addback mechanism to avoid affecting the clearing price, because EE for the delivery year is reflected in the revised load forecast model for the same delivery year. The combination of EE and the EE addback mechanism had a significant impact on the auction results but not on the auction clearing prices. The impact of EE and the addback mechanism was a result of customers paying for a significant level of EE MW and a zero impact from the market price increase as a result of the updated EE addback mechanism.

Table 33 shows the results if there were no offers for EE and the EE addback MW were removed in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. All clearing prices would have remained the same.[176] [177]

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2023/2023 RPM Base Residual Auction were $2,192,828,251. If there were no offers for EE and the EE addback MW were removed in the 2022/2023 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,073,286,830, a decrease of $119,541,421, or 5.5 percent, compared to the actual results. From another perspective, the inclusion of EE offers and the EE addback MW resulted in a 5.8 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE did not participate on the supply side. The 5.5 percent increase in total RPM market revenues reflects the amount of EE capacity purchased. EE accounted for 7,668.4 MW of the increase in cleared capacity.

Impact of Zero PRD Offers (Scenario 7)

The 2024/2025 RPM Base Residual Auction was the fifth BRA that included submissions for Price Responsive Demand (PRD). The inclusion of PRD had a limited impact on the auction results.

Table 34 shows the results if there were no offers for PRD in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $29.30 per MW-day, and the clearing quantity would have increased to 147,798.6 MW. The clearing quantity of seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have increased to $51.47 per MW-day, and the clearing quantity would have increased to 64,481.1 MW. The clearing quantity of seasonal capacity

176 The negligible price difference ($0.01) for RTO is due to computational precision differences in PJM’s clearing optimization and the MMU’s clearing optimization.

177 The cleared MW quantities under the scenario assumptions are very close to cleared MW in the actual BRA less the EE cleared MW. There are small changes among the LDAs but overall the total MW cleared in the scenario was 0.4 MW greater than the total MW cleared in the 2024/2025 BRA less the EE MW cleared.

for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $55.21 per MW-day, and the clearing quantity would have increased to 30,706.7 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have increased to 1,436.2 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $96.88 per MW-day, and the clearing quantity would have increased to 2,793.3 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no submissions from PRD providers in the 202342025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,259,815,834, an increase of $66,987,582, or 3.1 percent, compared to the actual results. From another perspective, the inclusion of PRD resulted in a 3.0 percent reduction in RPM revenues for the 2024/2025 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 Seasonal Offers (Scenario 8)

The 2024/2025 RPM Base Residual Auction was the fourth BRA held using the seasonal products for summer and winter capacity. The inclusion of seasonal offers (summer period capacity performance resources or winter period capacity performance resources) had a significant impact on the auction results. Summer period capacity performance resources include summer period demand resources, summer period energy efficiency resources, capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during the summer peak-hour periods consistently and measurably greater than its average expected energy output during winter peak hour periods.[178] This tariff language is vague and includes no actual metrics. Capacity storage resources include hydroelectric, flywheel and battery storage.

[178] OATT Attachment DD § 5.5A(e)(i).

Intermittent resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. Winter period capacity performance resources include capacity storage resources, intermittent resources, and environmentally limited resources that have an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.[179]

Table 35 shows the results if there were no offers for seasonal products (Demand Resources, Energy Efficiency Resources, and Generation Resources) in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $32.46 per MW-day, and the clearing quantity would have decreased to 147,147.6 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $49.71 per MW-day, and the clearing quantity would have decreased to 64,149.3 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 0 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $54.97 per MW-day, and the clearing quantity would have remained the same at 30,670.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have remained the same at 1,422.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for seasonal products in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,296,212,168, an increase of $103,383,917, or 4.7 percent, compared to the actual results. From another perspective, the inclusion of seasonal offers resulted in a 4.5 percent decrease in RPM revenues for the 2024/2025 RPM

[179] OATT Attachment DD § 5.5A(e)(ii).

Base Residual Auction compared to what RPM revenues would have been without any seasonal products.

Impact of Matching Seasonal Offers only Within LDAs (Scenario 9)

Matching seasonal offers across LDAs had a limited impact on the auction results.

Table 36 shows the results if seasonal offers were only matched with complementary seasonal offers within the same LDA in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $29.00 per MW-day, and the clearing quantity would have decreased to 147,451.0 MW. The clearing quantity of seasonal capacity would have decreased to 572.6 MW. The MAAC clearing price would have increased to $49.71 per MW-day, and the clearing quantity would have decreased to 64,170.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 20.8 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $54.97 per MW-day, and the clearing quantity would have remained the same at 30,670.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have remained the same at 1,422.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at to 0.0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0.0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If seasonal offers were not matched with complementary seasonal offers from the other LDAs in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues would have been $2,197,384,603, an increase of $4,556,351, or 0.2 percent, compared to the actual results. From another perspective, allowing the matching of offers from seasonal products across child LDAs in the same parent LDA resulted in a 0.2 percent decrease in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if seasonal offers were only matched with complementary seasonal offers within the same LDA.

Impact of Zero Capacity Imports (Scenario 10)

The inclusion of capacity imports in the 2024/2025 RPM Base Residual Auction had a significant impact on the auction results.

Table 38 shows the results if capacity imports in the 2024/2025 RPM Base Residual Auction had been eliminated and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $36.00 per MW-day, and the clearing quantity would have decreased to 147,472.5 MW. The clearing quantity of seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have decreased by $49.25 per MW-day, and the clearing quantity would have decreased to 64,172.6 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $54.97 per MW-day, and the clearing quantity would have remained the same at 30,670.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have remained the same at 1,422.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If capacity imports had been eliminated and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,400,001,217, an increase of $207,172,966, or 9.4 percent, compared to the actual results. From another perspective, the impact of including capacity imports resulted in a 8.6 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been if no capacity imports were included in the auction.

Impact of Combined Scenarios 4, 5, 6, 7, 8, 10 (Scenario 11)

The combined impact of issues related to the definition of capacity had a significant impact on the auction results. Together, the overstatement of intermittent MW offers, and the inclusion of sell offers from DR, EE, PRD, seasonal products, and imports had a significant combined impact on the auction results.

Table 39 shows the results if there were no offers for DR, EE, PRD, or seasonal products, imports, and no intermittent capacity overstatement in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the MAAC, EMAAC, BGE and DPL South import limits. The RTO clearing price would have increased to $168.38 per MW-day, and the clearing quantity would have decreased to 135,524.0 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $168.38 per MW-day, and the clearing quantity would have decreased to 61,795.3 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 0 MW. The DEOK clearing price would have increased to $243.86 per MW-day, and the clearing quantity would have decreased to 1,661.5 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $168.38 per MW-day, and the clearing quantity would have decreased to 28,230.3 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $168.38 per MW-day, and the clearing quantity would have decreased to 1,271.5 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $168.38 per MW-day, and the clearing quantity would have decreased to 2,325.1 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no overstatement of intermittent MW offers and no offers from DR, EE, PRD, seasonal products, or imports in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $8,374,917,524, an increase of $6,182,089,273, or 281.9 percent, compared to the actual results. From another perspective, the inclusion of overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal products and imports resulted in a 73.8 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without overstated intermittent MW offers, and offers from DR, EE, PRD, seasonal products and imports.

Impact of Market Behavior Issues

The MMU analyzed the impact of specific, significant issues related to market behavior, including: the impact of including all capacity categorically exempt from the RPM must offer requirement; the impact of excluding all capacity categorically exempt from the RPM must offer requirement; and the impact of all nuclear plants offering as price takers.

Impact of Inclusion of Zero Categorically Exempt Offers (Scenario 12)

The inclusion of capacity categorically exempt from the RPM must offer requirement had a significant impact on the auction results. This scenario is the case where no categorically exempt resources offered.

Table 40 shows the results if there were no offers for capacity resources categorically exempt from RPM must offer requirement in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the MAAC import limit. The RTO clearing price would have increased to $81.25 per MW-day, and the clearing quantity would have decreased to 145,773.2 MW. The clearing quantity of seasonal capacity would have decreased to 0 MW. The MAAC clearing price would have increased to $81.25 per MW-day, and the clearing quantity would have decreased to 64,098.5 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 0 MW. The DEOK clearing price would have increased to $181.49 per MW-day, and the clearing quantity would have decreased to 1,916.4 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $144.61 per MW-day, and the clearing quantity would have decreased to 29,993.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have increased to $364.64 per MW-day, and the clearing quantity would have decreased to 1,268.2 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $84.21 per MW-day, and the clearing quantity would have decreased to 2,646.9 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If there had been no offers for capacity resources categorically exempt from the RPM must offer requirement in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $5,200,707,712, an increase of $3,007,879,460, or 137.2 percent, compared to the actual results. From another perspective, the inclusion of offers for capacity resources categorically exempt from RPM must offer requirement resulted in a 57.8 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without offers from capacity resources categorically exempt from RPM must offer requirement.

Impact of Inclusion of All Categorically Exempt Offers (Scenario 13)

Capacity resources that were categorically exempt from the RPM must offer requirement and did not offer in the 2024/2025 RPM Base Residual Auction had a significant impact on the auction results. This scenario is the case where all categorically exempt resources were assumed to be offered at $0 per MW-day.

Table 41 shows the results had there been offers from capacity categorically exempt from the RPM must offer requirement that did not offer in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The sell offer prices for this additional capacity was set to $0 per MW-day. The binding constraints would have remained binding with the exception of the EMAAC import limit. The RTO clearing price would have decreased to $25.66 per MW-day, and the clearing quantity would have decreased to 145,162.6 MW. The clearing quantity of seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have decreased to $44.00 per MW-day, and the clearing quantity would have decreased to 63,021.1 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would remained the same at 52.7 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $44.00 per MW-day, and the clearing quantity would have decreased to 30,015.8 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have decreased to 1,420.7 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,921,538,019, a decrease of $271,290,232, or 12.4 percent, compared to the actual results. From another perspective, the categorical exemptions from the RPM must offer requirement resulted in a 14.1 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been had the categorically exempt resources been subject to the RPM must offer requirement.

Impact of Inclusion of All Nuclear Offers as Price Takers (Scenario 14)

Nuclear offer behavior in the 2022/2023 RPM Base Residual Auction was comparable to that in the 2021/2022 BRA. In both the 2022/2023 BRA and the 2021/2022 BRA a significant level of nuclear capacity was offered at higher sell offer prices than in the 2020/2021 BRA, and fewer nuclear MW cleared in the 2022/2023 BRA and 2021/2022 BRA than in the 2020/2021 RPM BRA. [180] [181] [182] 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 the competitive offer for all nuclear resources.

Table 42 shows the results of the 2024/2025 RPM Base Residual Auction had all nuclear offers been replaced with $0 per MW-day and everything else had remained the same. All binding constraints would have remained binding. The RTO clearing price would have increased to $28.93 per MW-day, and the clearing quantity would have decreased to 147,466.3 MW. The clearing quantity of seasonal capacity would have remained the same at 605.6 MW. The MAAC clearing price would have decreased to $48.35 per MW-day, and the clearing quantity would have decreased to 64,188.2 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have remained the same at 52.7 MW. The DEOK clearing price would have remained the same at $96.24 per MW-day, and the clearing quantity would have remained the same at 2,060.0 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have decreased to $49.49 per MW-day, and the clearing quantity would have increased to 30,710.5 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have remained the same at 1,422.0 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have remained the same at $73.00 per MW-day, and the clearing quantity

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[180] 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>.

[181] See PJM. News Releases, June 2, 2021. <https://www.pjm.com/-/media/about-pjm/newsroom/2021-releases/20210602-pjm-successfully-clears-capacity-auction-to-ensure-reliable-electricity-supplies.ashx>.

[182] See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 2, 2022).

would have remained the same at 2,671.6 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If all nuclear offers were replaced by $0 per MW-day nuclear offers in the 2023/2024 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $2,121,788,593, a decrease of $71,039,658, or 3.2 percent, compared to the actual results. From another perspective, the nuclear offers at levels exceeding $0 per MW-day resulted in a 3.3 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been had all nuclear offers been at $0 per MW-day.

Impact of Combined Scenarios 2, 4, 5, 10 (Scenario 15)

The impact of some of the identified market design flaws reduced capacity market prices and the impact of other identified market design flaws increased capacity market prices. The combined impact of the identified market design flaws was to reduce capacity market revenues by 53.8 percent in the 2024/2025 BRA. The identified market design flaws are: the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

Table 43 shows the results if all of the identified market design flaws had been corrected in the 2024/2025 RPM Base Residual Auction and everything else had remained the same. The binding constraints would have remained binding with the exception of the MAAC, EMAAC and BGE import limits. The RTO clearing price would have increased to $90.00 per MW-day, and the clearing quantity would have decreased to 142,653.2 MW. The clearing quantity of seasonal capacity would have decreased to 297.8 MW. The MAAC clearing price would have increased to $90.00 per MW-day, and the clearing quantity would have decreased to 64,107.8 MW. The clearing quantity of seasonal capacity for satisfying MAAC's reliability requirement would have decreased to 20.2 MW. The DEOK clearing price would have increased to $181.21 per MW-day, and the clearing quantity would have decreased to 1,845.4 MW. The clearing quantity of seasonal capacity for satisfying DEOK's reliability requirement would have remained the same at 0 MW. The EMAAC clearing price would have increased to $90.00 per MW-day, and the clearing quantity would have decreased to 30,013.0 MW. The clearing quantity of seasonal capacity for satisfying EMAAC's reliability requirement would have remained the same at 0 MW. The DPL South clearing price would have remained the same at $90.64 per MW-day, and the clearing quantity would have decreased to 1,349.3 MW. The clearing quantity of seasonal capacity for satisfying DPL South's reliability requirement would have remained the same at 0 MW. The BGE clearing price would have increased to $90.00 per MW-day, and the clearing quantity would have decreased to 2,585.4 MW. The clearing quantity of seasonal capacity for satisfying BGE's reliability requirement would have remained the same at 0 MW.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,192,828,251. If all of the identified market design flaws had been corrected in the 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $4,749,749,993, an increase of $2,556,921,742, or 116.6 percent, compared to the actual results. From another perspective, the identified market design flaws resulted in a 53.8 percent reduction in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been without those flaws.

Tables and Figures for RTO Market

Table 7 RTO offer statistics: 2024/2025 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	190,630.0	180,985.3		
DR capacity	10,327.2	11,242.5		
EE capacity	7,943.5	8,651.5		
Generation winter capacity	990.1	990.1		
Total internal RTO capacity	209,890.8	201,869.4		
FRR	(34,618.5)	(32,379.9)		
Imports	1,617.1	1,527.1		
RPM capacity	176,889.4	171,016.6		
Exports	(2,577.7)	(2,500.4)		
FRR optional	(1,233.0)	(921.9)		
Excused Existing Generation Capacity Resources	(4,724.9)	(3,583.0)		
Unoffered Planned Generation Capacity Resources	(157.0)	(149.9)		
Unoffered Intermittent Resources	(3,873.4)	(3,872.0)		
Unoffered Capacity Storage Resources	(1,305.8)	(1,305.8)		
Unoffered generation winter capacity	(594.5)	(594.5)		
Unoffered DR and EE	(1,439.2)	(1,567.7)		
Available	160,983.9	156,521.4	100.0%	100.0%
Generation offered	144,324.6	138,382.7	89.7%	88.4%
DR offered	9,312.1	10,136.6	5.8%	6.5%
EE offered	7,347.2	8,002.0	4.6%	5.1%
Total offered	160,983.9	156,521.4	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Table 8 Capacity modifications (ICAP): 2024/2025 RPM Base Residual Auction[183]

	ICAP (MW)					
	RTO	MAAC	EMAAC	DPL South	BGE	DEOK
Generation increases	1,914.9	435.3	161.6	119.2	4.1	6.9
Generation decreases	(925.9)	(240.1)	(77.0)	(6.1)	0.0	(13.8)
Capacity modifications net increase/(decrease)	989.0	195.2	84.6	113.1	4.1	(6.9)
DR increases	590.9	195.8	94.3	2.3	30.4	57.7
DR decreases	(1,226.7)	(554.9)	(272.0)	(7.5)	(13.9)	(28.5)
DR net increase/(decrease)	(635.8)	(359.1)	(177.7)	(5.2)	16.5	29.2
EE increases	3,206.5	1,551.5	995.9	45.0	136.0	60.4
EE decreases	(300.8)	(73.2)	(31.3)	0.0	(10.7)	(16.2)
EE modifications increase/(decrease)	2,905.7	1,478.3	964.6	45.0	125.3	44.2
Net internal capacity increase/(decrease)	3,258.9	1,314.4	871.5	152.9	145.9	66.5

Table 9 Capacity modifications (UCAP): 2024/2025 RPM Base Residual Auction

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	BGE	DEOK
Generation increases	1,911.8	435.6	161.5	119.2	4.1	6.9
Generation decreases	(893.9)	(229.0)	(76.0)	(6.0)	0.0	(13.6)
Capacity modifications net increase/(decrease)	1,017.9	206.6	85.5	113.2	4.1	(6.7)
DR increases	638.3	208.2	102.3	2.5	27.8	63.2
DR decreases	(1,337.0)	(604.7)	(296.5)	(8.2)	(15.1)	(31.1)
DR net increase/(decrease)	(698.7)	(396.5)	(194.2)	(5.7)	12.7	32.1
EE increases	3,493.8	1,690.7	1,085.1	49.1	148.3	65.7
EE decreases	(327.6)	(79.5)	(34.0)	0.0	(11.7)	(17.6)
EE modifications increase/(decrease)	3,166.2	1,611.2	1,051.1	49.1	136.6	48.1
Net capacity/DR/EE modifications increase/(decrease)	3,485.4	1,421.3	942.4	156.6	153.4	73.5
EFORd effect	(1,090.9)	(557.9)	(163.0)	(40.1)	(98.4)	(83.5)
DR and EE effect	(13.4)	(5.2)	(2.3)	0.0	(0.9)	(0.2)
Net internal capacity increase/(decrease)	2,381.1	858.2	777.1	116.5	54.1	(10.2)

183 Only cap mods that had a start date on or before June 1, 2024, and DR and EE plans for the 2024/2025 RPM Base Residual Auction are included.

Table 10 Winter capacity modifications (ICAP): 2024/2025 RPM Base Residual Auction

	ICAP (MW)					
	RTO	MAAC	EMAAC	DPL South	BGE	DEOK
Generation increases	306.2	33.8	0.0	0.0	0.0	0.0
Generation decreases	(243.4)	(10.3)	0.0	0.0	0.0	0.0
Capacity modifications net increase/(decrease)	62.8	23.5	0.0	0.0	0.0	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
Net internal capacity increase/(decrease)	62.8	23.5	0.0	0.0	0.0	0.0

Table 11 Winter capacity modifications (UCAP): 2024/2025 RPM Base Residual Auction

	UCAP (MW)					
	RTO	MAAC	EMAAC	DPL South	BGE	DEOK
Generation increases	306.2	33.8	0.0	0.0	0.0	0.0
Generation decreases	(243.4)	(10.3)	0.0	0.0	0.0	0.0
Capacity modifications net increase/(decrease)	62.8	23.5	0.0	0.0	0.0	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)	62.8	23.5	0.0	0.0	0.0	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)	62.8	23.5	0.0	0.0	0.0	0.0

Table 12 Installed and offered generation capacity by parent company: 2024/2025 RPM Base Residual Auction

Parent Company	ICAP (MW)	Percent of Total ICAP	Offered ICAP (MW)	Percent of Total Offered ICAP
Dominion Resources, Inc.	22,237.7	11.5%	231.0	0.2%
Constellation Energy Generation, LLC	20,184.5	10.4%	19,017.3	13.2%
American Electric Power Company, Inc.	15,434.7	8.0%	2,352.2	1.6%
ArcLight Capital Partners, LLC	14,319.7	7.4%	13,264.7	9.2%
LS Power Group	11,019.3	5.7%	10,939.3	7.6%

Table 13 Net load prices: 2024/2025 RPM Base Residual Auction

	$ per MW-day					
	RTO	MAAC	EMAAC	DPL	BGE	DEOK
Resource clearing price	$28.92	$49.49	$54.95	$90.64	$73.00	$96.24
Preliminary zonal capacity price	$28.92	$49.49	$54.95	$65.84	$73.04	$96.24
Adjusted preliminary zonal capacity price	$28.99	$49.68	$55.14	$66.15	$73.87	$96.31
Base zonal CTR credit rate	$0.00	$0.00	$0.65	$0.07	$14.04	$38.81
Preliminary net load price	$28.99	$49.68	$54.50	$66.07	$59.83	$57.50

Table 14 Clearing prices: 2023/2024 and 2024/2025 RPM Base Residual Auctions

			Change	
LDA	2023/2024 BRA	2024/2025 BRA	$ per MW-Day	Percent
RTO	$34.13	$28.92	($5.21)	(18.0%)
MAAC	$49.49	$49.49	$0.00	0.0%
EMAAC	$49.49	$54.95	$5.46	9.9%
SWMAAC	$49.49	$49.49	$0.00	0.0%
PSEG	$49.49	$54.95	$5.46	9.9%
PSEG North	$49.49	$54.95	$5.46	9.9%
DPL South	$69.95	$90.64	$20.69	22.8%
Pepco	$49.49	$49.49	$0.00	0.0%
ATSI	$34.13	$28.92	($5.21)	(18.0%)
ATSI Cleveland	$34.13	$28.92	($5.21)	(18.0%)
ComEd	$34.13	$28.92	($5.21)	(18.0%)
BGE	$69.95	$73.00	$3.05	4.2%
PPL	$49.49	$49.49	$0.00	0.0%
DAY	$34.13	$28.92	($5.21)	(18.0%)
DEOK	$34.13	$96.24	$62.11	64.5%

Table 15 Reserve margin: 2024/2025 RPM Base Residual Auction

	Reserve Margin Calculation	
Forecast peak load ICAP (MW)	150,640.3	A
FRR peak load ICAP (MW)	29,421.6	B
PRD ICAP (MW)	305.0	C
Installed reserve margin (IRM)	14.7%	D
Pool-wide average EFORd	5.02%	E
Forecast pool requirement (FPR)	1.0894	F=(1+D)*(1-E)
Cleared UCAP (generation and DR)	139,810.2	G
Cleared ICAP (generation and DR)	147,199.6	H=G/(1-E)
RPM peak load ICAP (MW)	120,913.7	J=A-B-C
Reserve margin ICAP (MW)	26,285.9	K=H-J
Reserve margin (%)	21.7%	L=K/J
Reserve cleared in excess of IRM ICAP (MW)	8,511.6	M=K-D*J
Reserve cleared in excess of IRM (%)	7.0%	N=M/J
RPM peak load UCAP (MW)	114,843.8	P=J*(1-E)
RPM reliability requirement UCAP (MW)	131,723.4	Q=J*F
Reserve margin UCAP (MW)	24,966.4	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	8,086.8	S=G-Q

Table 16 Net excess: 2024/2025 RPM Base Residual Auction

	UCAP (MW)						
	RTO	MAAC	EMAAC	DPL South	BGE	DEOK	
Cleared generation and DR	139,810.2	60,759.2	28,702.5	1,322.2	2,292.2	1,874.0	A
CETL	NA	5,965.0	8,594.0	1,962.0	5,397.0	4,999.0	B
Reliability requirement	164,107.6	63,518.0	35,415.0	3,153.0	7,514.0	6,881.0	C
FRR peak load	29,421.6	0.0	0.0	0.0	0.0	787.9	D
PRD	305.0	305.0	35.0	13.0	160.0	0.0	E
FPR	1.0894	1.0894	1.0894	1.0894	1.0894	1.0894	F
Reliability requirement adjusted for FRR and PRD	131,723.4	63,185.7	35,376.9	3,138.8	7,339.7	6,022.6	G=C-D*F-E*F
Net excess/(deficit)	8,086.8	3,538.5	1,919.6	145.4	349.5	850.4	H=A+B-G

Table 17 Offered and cleared capacity by LDA, resource type, and season type: 2024/2025 RPM Base Residual Auction

		Offered UCAP (MW)			Cleared UCAP (MW)		
LDA	Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
RTO	GEN	137,649.8	210.0	522.9	131,275.9	208.9	522.9
RTO	DR	9,942.8	166.8	27.0	7,804.3	159.1	27.0
RTO	EE	7,580.1	421.9	0.0	7,289.7	191.1	0.0
MAAC	GEN	61,903.6	0.0	26.1	58,311.6	0.0	26.1
MAAC	DR	2,966.0	9.2	0.0	2,491.0	7.1	0.0
MAAC	EE	3,366.1	155.9	0.0	3,345.5	77.9	0.0
EMAAC	GEN	28,272.9	0.0	0.0	27,762.8	0.0	0.0
EMAAC	DR	1,260.5	1.6	0.0	1,001.0	0.0	0.0
EMAAC	EE	1,926.8	99.9	0.0	1,906.7	62.3	0.0
DPL South	GEN	1,302.7	0.0	0.0	1,280.1	0.0	0.0
DPL South	DR	46.0	0.0	0.0	42.1	0.0	0.0
DPL South	EE	99.8	0.2	0.0	99.8	0.1	0.0
BGE	GEN	2,325.1	0.0	0.0	2,094.9	0.0	0.0
BGE	DR	224.1	0.0	0.0	198.1	0.0	0.0
BGE	EE	379.1	7.0	0.0	378.6	0.9	0.0
DEOK	GEN	1,682.5	0.0	0.0	1,654.2	0.0	0.0
DEOK	DR	231.2	0.0	0.0	221.9	0.0	0.0
DEOK	EE	183.9	9.2	0.0	183.9	2.1	0.0

Table 18 Weighted average sell offer prices by LDA, resource type, and season type: 2024/2025 RPM Base Residual Auction

		Weighted-Average ($ per MW-day UCAP)		
LDA	Resource Type	Annual	Summer	Winter
RTO	GEN	$9.33	$0.00	$2.83
RTO	DR	$26.13	$0.36	$0.00
RTO	EE	$8.00	$2.98	

Table 19 Offered generation capacity by season type and price range relative to market seller offer cap (MSOC): 2024/2025 RPM Base Residual Auction

	Offered UCAP (MW)		
Season Type	< MSOC	= MSOC	> MSOC
Annual	59,438.7	78,211.1	0.0
Summer	0.0	210.0	0.0
Winter	0.0	522.9	0.0

Table 20 Weighted average sell offer prices and market seller offer caps: 2022/2023; 2023/2024; 2024/2025 RPM Base Residual Auctions[184]

			Weighted-Average ($ per MW-day UCAP)		
Base Residual Auction	LDA	Resource Type	Sell Offers	Market Seller Offer Caps	Ratio of Sell Offers to Market Seller Offer Caps
2022/2023	RTO	GEN	$36.77	$162.70	0.23
2023/2024	RTO	GEN	$10.44	$26.70	0.39
2024/2025	RTO	GEN	$9.30	$29.90	0.31

Table 21 Cleared MW by zone and resource type/fuel source: 2024/2025 RPM Base Residual Auction[185]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydro	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	66.8	149.2	0.0	1,084.0	0.0	0.0	0.0	10.7	0.0	0.0	1,310.7
AEP	1,093.3	787.4	5,230.2	11,546.1	56.6	0.0	0.0	814.4	0.0	337.1	19,865.1
AP	635.1	373.6	3,729.0	3,849.1	98.4	0.0	0.0	170.0	0.0	78.5	8,933.6
ATSI	674.6	583.5	125.4	5,518.1	0.0	2,109.4	490.2	219.4	0.0	0.0	9,720.6
BGE	198.1	379.5	1,518.0	336.0	0.0	1,702.1	198.9	0.0	42.0	0.0	4,374.6
ComEd	1,556.3	978.5	1,813.7	9,967.2	0.0	10,008.0	240.6	0.0	0.0	591.8	25,156.1
DAY	191.1	127.7	0.0	601.3	0.0	0.0	33.7	35.2	0.0	0.0	988.9
DEOK	221.9	186.0	922.9	520.0	73.5	0.0	33.0	104.8	0.0	0.0	2,062.1
DLCO	120.6	131.3	0.0	302.0	0.0	1,310.9	16.3	6.3	0.0	0.0	1,887.4
Dominion	710.5	889.4	418.5	4,244.9	1,052.6	218.5	20.0	1,159.8	131.6	17.5	8,863.3
DPL	147.7	200.4	0.0	3,762.1	0.0	0.0	572.9	179.5	0.0	0.0	4,862.6
EKPC	289.0	0.0	1,644.9	1,063.6	121.5	0.0	0.0	57.8	0.0	0.0	3,176.8
External	0.0	0.0	820.4	160.8	316.8	99.6	0.0	0.0	0.0	0.0	1,397.6
JCPL	131.8	316.1	0.0	2,956.7	406.0	0.0	184.0	37.1	0.0	0.0	4,031.7
Met-Ed	218.8	155.8	0.0	2,597.5	16.4	0.0	393.0	43.7	51.4	0.0	3,476.6
OVEC	0.0	0.0	1,154.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,154.3
PECO	366.3	575.8	0.0	4,130.1	494.3	4,745.9	750.4	0.0	98.6	0.0	11,161.4
PENELEC	314.0	139.8	3,359.3	2,735.8	500.6	0.0	82.3	87.7	36.4	136.7	7,392.6
Pepco	157.5	393.3	0.0	3,339.0	0.0	0.0	176.5	0.8	44.5	0.0	4,111.6
PPL	608.7	386.1	2,343.2	7,770.5	577.4	2,422.6	41.0	27.3	8.1	0.0	14,184.9
PSEG	285.7	724.3	0.0	4,976.0	0.7	3,200.9	0.0	9.0	163.9	0.0	9,360.5
RECO	2.7	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9
Total	7,990.5	7,480.8	23,079.8	71,460.8	3,714.8	25,817.9	3,232.8	2,963.5	576.5	1,161.6	147,478.9

184 The underlying data used for Table 18 includes all sell offers. The underlying data used for Table 20 includes only those sell offers subject to market seller offer caps.

185 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, 3,200.9 MW of the 9,360.5 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 22 Uncleared generation offers by technology type and age: 2024/2025 RPM Base Residual Auction[186] [187]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal fired	253.5	2,671.2	2,924.7
Combustion turbine	1,945.2	212.2	2,157.4
Other	288.1	978.2	1,266.3
Total	2,486.8	3,861.6	6,348.4

Table 23 Uncleared generation resources in multiple auctions[188] [189]

	2024/2025		2023/2024 Results for Same Set of Resources		2022/2023 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	2,924.7	17	3,818.4	15	686.3	11
Combustion turbine	2,157.4	41	1,571.6	22	384.1	13
Other	1,266.3	14	0.0	0	0.0	0
Total	6,348.4	72	5,390.0	37	1,070.4	24

186 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 2024/2025 BRA, waste coal resources are included in the coal fired category.

187 Data aggregated based on PJM confidentiality rules.

188 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 2024/2025 BRA, waste coal resources are included in the coal fired category.

189 Data aggregated based on PJM confidentiality rules.

Table 24 Offers greater than $35.00 per MW-day in total RTO supply curve: 2024/2025 RPM Base Residual Auction[190] [191]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	4,732.4	35.8%
Combustion turbine	2,800.5	21.2%
Demand Resource	2,157.0	16.3%
Other (combined cycle, energy efficiency, nuclear, oil or gas steam)	3,538.0	26.7%
Total	13,227.9	100.0%

Table 25 PJM LDA CETL and CETO values: 2023/2024 and 2024/2025 RPM Base Residual Auctions

	2023/2024			2024/2025			Change			
							CETO		CETL	
LDA	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	MW	Percent	MW	Percent
MAAC	(4,660.0)	6,381.0	(136.9%)	(4,760.0)	5,965.0	(125.3%)	(100.0)	2.1%	(416.0)	(6.5%)
EMAAC	3,210.0	8,704.0	271.2%	2,740.0	8,594.0	313.6%	(470.0)	(14.6%)	(110.0)	(1.3%)
SWMAAC	5,790.0	8,389.0	144.9%	6,060.0	7,947.0	131.1%	270.0	4.7%	(442.0)	(5.3%)
PSEG	5,450.0	9,022.0	165.5%	5,630.0	8,287.0	147.2%	180.0	3.3%	(735.0)	(8.1%)
PSEG North	2,420.0	4,349.0	179.7%	2,560.0	4,253.0	166.1%	140.0	5.8%	(96.0)	(2.2%)
DPL South	1,360.0	2,008.0	147.6%	1,420.0	1,962.0	138.2%	60.0	4.4%	(46.0)	(2.3%)
Pepco	3,940.0	7,160.0	181.7%	4,220.0	7,033.0	166.7%	280.0	7.1%	(127.0)	(1.8%)
ATSI	4,230.0	10,213.0	241.4%	5,080.0	10,465.0	206.0%	850.0	20.1%	252.0	2.5%
ATSI Cleveland	3,550.0	4,728.0	133.2%	3,560.0	4,941.0	138.8%	10.0	0.3%	213.0	4.5%
ComEd	(4,060.0)	5,781.0	(142.4%)	(4,570.0)	4,640.4	(101.5%)	(510.0)	12.6%	(1,140.6)	(19.7%)
BGE	4,660.0	5,615.0	120.5%	4,660.0	5,397.0	115.8%	0.0	0.0%	(218.0)	(3.9%)
PPL	0.0	4,916.0	NA	(30.0)	4,337.0	(14,456.7%)	(30.0)	NA	(579.0)	(11.8%)
DAY	2,510.0	4,022.0	160.2%	2,470.0	3,918.0	158.6%	(40.0)	(1.6%)	(104.0)	(2.6%)
DEOK	3,270.0	5,632.0	172.2%	3,270.0	4,999.0	152.9%	0.0	0.0%	(633.0)	(11.2%)

190 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 2024/2025 BRA, waste coal resources are included in the coal fired category.

191 Data aggregated based on PJM confidentiality rules.

Figure 1 Shape of the VRR curve relative to the reliability requirement: 2024/2025 RPM Base Residual Auction

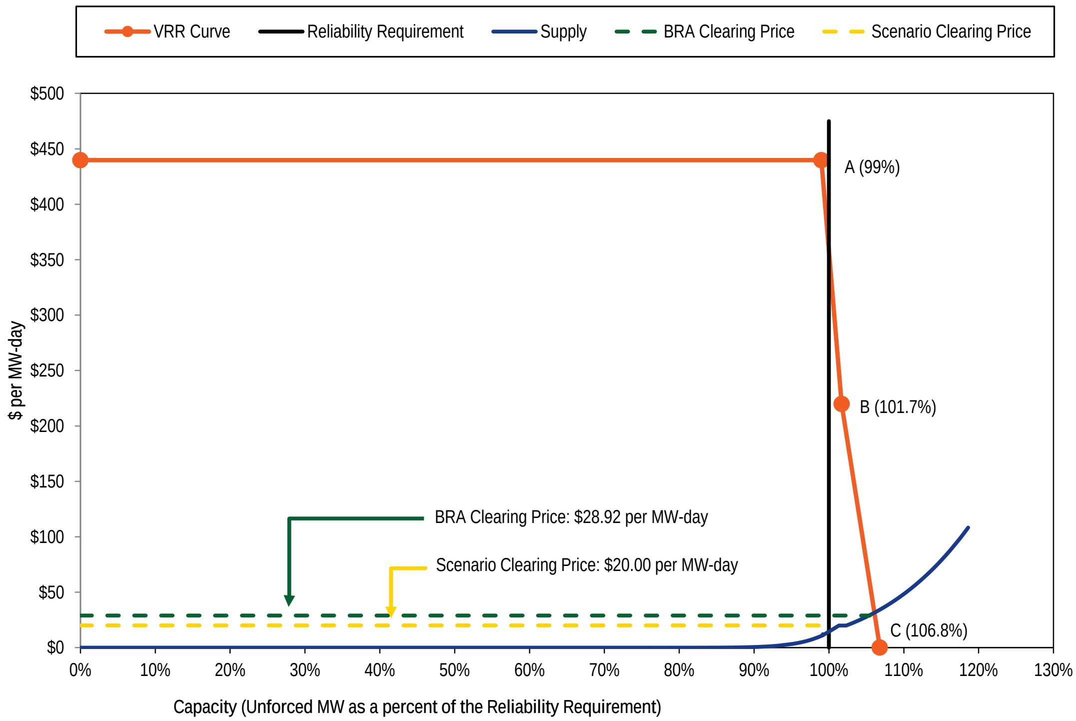


Table 26 Impact of using downward sloping VRR curve: 2024/2025 RPM Base Residual Auction

Scenario 1

		Actual Auction Results		Impact of Using Vertical Reliability Requirement	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$20.00	138,786.5
	Summer	$28.92	605.6	$20.00	605.6
	Winter	$28.92	605.6	$20.00	605.6
RTO Total			147,478.9		139,392.1
MAAC	Annual	$49.49	64,148.1	$35.00	60,561.8
	Summer	$49.49	52.7	$35.00	52.7
	Winter	$49.49	52.7	$35.00	52.7
MAAC Total			64,200.8		60,614.5
DEOK	Annual	$96.24	2,060.0	$20.00	1,860.4
	Summer	$96.24	0.0	$20.00	0.0
	Winter	$96.24	0.0	$20.00	0.0
DEOK Total			2,060.0		1,860.4
EMAAC	Annual	$54.95	30,670.5	$36.90	28,689.5
	Summer	$54.95	0.0	$36.90	0.0
	Winter	$54.95	0.0	$36.90	0.0
EMAAC Total			30,670.5		28,689.5
DPL South	Annual	$90.64	1,422.0	$54.81	1,276.6
	Summer	$90.64	0.0	$54.81	0.0
	Winter	$90.64	0.0	$54.81	0.0
DPL South Total			1,422.0		1,276.6
BGE	Annual	$73.00	2,671.6	$35.00	2,325.0
	Summer	$73.00	0.0	$35.00	0.0
	Winter	$73.00	0.0	$35.00	0.0
BGE Total			2,671.6		2,325.0

Table 27 Impact of using modified VRR curve: 2024/2025 RPM Base Residual Auction Scenario 2

		Actual Auction Results		Impact of Using Modified Reliability Requirement	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$22.50	142,406.0
	Summer	$28.92	605.6	$22.50	605.6
	Winter	$28.92	605.6	$22.50	605.6
RTO Total			147,478.9		143,011.6
MAAC	Annual	$49.49	64,148.1	$43.00	62,378.5
	Summer	$49.49	52.7	$43.00	52.7
	Winter	$49.49	52.7	$43.00	52.7
MAAC Total			64,200.8		62,431.2
DEOK	Annual	$96.24	2,060.0	$31.75	1,969.1
	Summer	$96.24	0.0	$31.75	0.0
	Winter	$96.24	0.0	$31.75	0.0
DEOK Total			2,060.0		1,969.1
EMAAC	Annual	$54.95	30,670.5	$43.00	29,836.7
	Summer	$54.95	0.0	$43.00	0.0
	Winter	$54.95	0.0	$43.00	0.0
EMAAC Total			30,670.5		29,836.7
DPL South	Annual	$90.64	1,422.0	$90.64	1,349.3
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,349.3
BGE	Annual	$73.00	2,671.6	$85.00	2,483.2
	Summer	$73.00	0.0	$85.00	0.0
	Winter	$73.00	0.0	$85.00	0.0
BGE Total			2,671.6		2,483.2

Table 28 Peak load forecast history[192] [193]

	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	2023 / 2024	149,680.0	NA	NA	149,382.2		NA	NA	(0.2%)	
Installed Reverve Margin		14.8%	NA	NA	14.9%		NA	NA	0.7%	
Pool Wide EFORd		5.04%	NA	NA	4.87%		NA	NA	(3.4%)	
Forecast Pool Requirement		1.0901	NA	NA	1.093		NA	NA	0.3%	
Reliability Requirement		163,166.2	NA	NA	163,274.7		NA	NA	0.1%	
Forecast Peak Load	2022 / 2023	150,229.0	NA	NA	149,263.6	147,771.2	NA	NA	(0.6%)	(1.6%)
Installed Reverve Margin		14.5%	NA	NA	14.9%		NA	NA	2.8%	
Pool Wide EFORd		5.08%	NA	NA	5.08%		NA	NA	0.0%	
Forecast Pool Requirement		1.0868	NA	NA	1.0906		NA	NA	0.3%	
Reliability Requirement		163,268.9	NA	NA	162,786.9		NA	NA	(0.3%)	
Forecast Peak Load	2021 / 2022	152,647.4	151,832.3	147,501.6	149,482.9	148,750.9	(0.5%)	(3.4%)	(2.1%)	(2.6%)
Installed Reverve Margin		15.8%	15.8%	15.1%	14.7%		0.0%	(4.4%)	(7.0%)	
Pool Wide EFORd		5.89%	6.01%	5.56%	5.22%		2.0%	(5.6%)	(11.4%)	
Forecast Pool Requirement		1.0898	1.0884	1.087	1.0871		(0.1%)	(0.3%)	(0.2%)	
Reliability Requirement		166,355.1	165,254.3	160,334.2	162,502.9		(0.7%)	(3.6%)	(2.3%)	
Forecast Peak Load	2020 / 2021	153,915.0	152,245.4	151,155.1	148,355.3	144,572.8	(1.1%)	(1.8%)	(3.6%)	(6.1%)
Installed Reverve Margin		16.6%	15.90%	15.9%	15.5%		(4.2%)	(4.2%)	(6.6%)	
Pool Wide EFORd		6.59%	5.97%	6.04%	5.78%		(9.4%)	(8.3%)	(12.3%)	
Forecast Pool Requirement		1.0892	1.0898	1.0890	1.0882		0.1%	(0.0%)	(0.1%)	
Reliability Requirement		167,644.2	165,917.0	164,607.9	161,440.2		(1.0%)	(1.8%)	(3.7%)	
Forecast Peak Load	2019 / 2020	157,188.5	154,510.0	152,760.7	151,643.5	151,552.2	(1.7%)	(2.8%)	(3.5%)	(3.6%)
Installed Reverve Margin		16.5%	16.60%	15.9%	16.0%		0.6%	(3.6%)	(3.0%)	
Pool Wide EFORd		6.60%	6.59%	5.99%	6.08%		(0.2%)	(9.2%)	(7.9%)	
Forecast Pool Requirement		1.0881	1.0892	1.0896	1.0895		0.1%	0.1%	0.1%	
Reliability Requirement		171,036.8	168,292.3	166,448.1	165,215.6		(1.6%)	(2.7%)	(3.4%)	

192 Typically, the time between the BRA and the 3rd IA is two years and 10 months but recent auctions have been delayed. The 2022/2023 BRA was originally scheduled for May 2019 but was delayed until June 2021. The First and Second IAs for 2022/2023 were not held and the Third IA was held in March 2022, just over nine months after the 2022/2023 BRA. The 2023/2024 BRA was held in June 2022 and the 2023/2024 Third IA was held in March 21, 2023. The First and Second IAs for 2023/2024 were not held.

193 PJM made changes to the load forecast model in December 2015. See Revision History (Revision 29) in *PJM Manual 19: Load Forecasting and Analysis (December 5, 2019)* 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. The revised load forecast model was used for the Second IA and Third IA for 2017/2018, all incremental auctions for 2018/2019 and for all auctions for 2019/2020 and subsequent delivery years.

Table 29 Impact of over forecasted peak load: 2024/2025 RPM Base Residual Auction Scenario 3

		Actual Auction Results		Reduce the Load Forecast by 2.0%	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$23.00	143,047.9
	Summer	$28.92	605.6	$23.00	605.6
	Winter	$28.92	605.6	$23.00	605.6
RTO Total			147,478.9		143,653.5
MAAC	Annual	$49.49	64,148.1	$44.00	62,839.8
	Summer	$49.49	52.7	$44.00	52.7
	Winter	$49.49	52.7	$44.00	52.7
MAAC Total			64,200.8		62,892.5
DEOK	Annual	$96.24	2,060.0	$51.73	2,012.5
	Summer	$96.24	0.0	$51.73	0.0
	Winter	$96.24	0.0	$51.73	0.0
DEOK Total			2,060.0		2,012.5
EMAAC	Annual	$54.95	30,670.5	$44.90	29,979.7
	Summer	$54.95	0.0	$44.90	0.0
	Winter	$54.95	0.0	$44.90	0.0
EMAAC Total			30,670.5		29,979.7
DPL South	Annual	$90.64	1,422.0	$132.40	1,324.9
	Summer	$90.64	0.0	$132.40	0.0
	Winter	$90.64	0.0	$132.40	0.0
DPL South Total			1,422.0		1,324.9
BGE	Annual	$73.00	2,671.6	$85.00	2,488.4
	Summer	$73.00	0.0	$85.00	0.0
	Winter	$73.00	0.0	$85.00	0.0
BGE Total			2,671.6		2,488.4

Table 30 Impact of overstated intermittent capacity: 2024/2025 RPM Base Residual Auction

Scenario 4

LDA	Product Type	Actual Auction Results Clearing Prices ($ per MW-day)	Actual Auction Results Cleared UCAP (MW)	Adjusted Intermittent MW Clearing Prices ($ per MW-day)	Adjusted Intermittent MW Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$31.22	147,067.9
	Summer	$28.92	605.6	$31.22	297.8
	Winter	$28.92	605.6	$31.22	297.8
RTO Total			147,478.9		147,365.7
MAAC	Annual	$49.49	64,148.1	$49.49	64,136.3
	Summer	$49.49	52.7	$49.49	20.2
	Winter	$49.49	52.7	$49.49	20.2
MAAC Total			64,200.8		64,156.5
DEOK	Annual	$96.24	2,060.0	$106.48	2,042.7
	Summer	$96.24	0.0	$106.48	0.0
	Winter	$96.24	0.0	$106.48	0.0
DEOK Total			2,060.0		2,042.7
EMAAC	Annual	$54.95	30,670.5	$55.00	30,670.1
	Summer	$54.95	0.0	$55.00	0.0
	Winter	$54.95	0.0	$55.00	0.0
EMAAC Total			30,670.5		30,670.1
DPL South	Annual	$90.64	1,422.0	$101.78	1,413.5
	Summer	$90.64	0.0	$101.78	0.0
	Winter	$90.64	0.0	$101.78	0.0
DPL South Total			1,422.0		1,413.5
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

Table 31 DR and EE statistics by LDA: 2023/2024 and 2024/2025 RPM Base Residual Auctions

		2023/2024 BRA			2024/2025 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	9,299.6	10,135.7	8,115.2	9,312.1	10,136.6	7,990.5	12.4	0.1%	0.9	0.0%	(124.8)	(1.5%)
RTO	EE	4,905.5	5,346.8	5,346.8	7,347.2	8,002.0	7,480.8	2,441.7	49.8%	2,655.2	49.7%	2,134.0	39.9%
MAAC	DR	2,826.8	3,080.1	2,403.9	2,737.3	2,975.2	2,498.1	(89.6)	(3.2%)	(105.0)	(3.4%)	94.2	3.9%
MAAC	EE	1,996.5	2,176.0	2,176.0	3,233.9	3,522.0	3,423.4	1,237.5	62.0%	1,346.0	61.9%	1,247.5	57.3%
EMAAC	DR	1,182.2	1,288.4	975.9	1,159.3	1,262.1	1,001.0	(22.9)	(1.9%)	(26.3)	(2.0%)	25.1	2.6%
EMAAC	EE	1,072.0	1,168.4	1,168.4	1,860.9	2,026.7	1,969.0	788.9	73.6%	858.3	73.5%	800.6	68.5%
SWMAAC	DR	406.5	442.6	336.1	417.2	448.7	355.6	10.6	2.6%	6.0	1.4%	19.5	5.8%
SWMAAC	EE	489.8	533.9	533.9	725.9	790.5	772.8	236.1	48.2%	256.7	48.1%	238.9	44.7%
DPL South	DR	49.4	53.8	52.2	42.3	46.0	42.1	(7.1)	(14.4%)	(7.8)	(14.5%)	(10.1)	(19.3%)
DPL South	EE	47.0	51.2	51.2	91.7	100.0	99.9	44.7	95.1%	48.8	95.3%	48.7	95.0%
PSEG	DR	365.0	398.0	272.7	355.8	387.4	285.7	(9.2)	(2.5%)	(10.6)	(2.7%)	13.0	4.8%
PSEG	EE	349.4	380.9	380.9	686.9	748.2	724.3	337.5	96.6%	367.3	96.4%	343.5	90.2%
PSEG North	DR	158.1	172.3	126.1	126.5	137.8	98.2	(31.6)	(20.0%)	(34.5)	(20.0%)	(27.9)	(22.1%)
PSEG North	EE	161.1	175.6	175.6	330.9	360.4	353.0	169.8	105.4%	184.7	105.2%	177.4	101.0%
Pepco	DR	212.0	230.7	167.7	206.2	224.6	157.5	(5.9)	(2.8%)	(6.2)	(2.7%)	(10.2)	(6.1%)
Pepco	EE	254.7	277.6	277.6	371.3	404.5	393.3	116.6	45.8%	126.9	45.7%	115.7	41.7%
ATSI	DR	1,009.2	1,100.1	851.5	875.5	953.5	674.6	(133.7)	(13.2%)	(146.6)	(13.3%)	(176.9)	(20.8%)
ATSI	EE	385.7	420.3	420.3	598.9	652.3	583.5	213.2	55.3%	232.0	55.2%	163.2	38.8%
ATSI Cleveland	DR	204.1	222.4	162.8	194.0	211.2	141.6	(10.1)	(4.9%)	(11.2)	(5.0%)	(21.2)	(13.0%)
ATSI Cleveland	EE	39.4	42.9	42.9	55.9	60.8	54.9	16.5	41.8%	17.9	41.8%	12.0	28.0%
ComEd	DR	1,504.7	1,640.3	1,286.9	1,753.0	1,909.2	1,556.3	248.3	16.5%	268.9	16.4%	269.4	20.9%
ComEd	EE	815.5	888.8	888.8	1,062.1	1,157.0	978.5	246.7	30.2%	268.2	30.2%	89.7	10.1%
BGE	DR	194.5	211.9	168.4	211.0	224.1	198.1	16.5	8.5%	12.2	5.8%	29.7	17.6%
BGE	EE	235.1	256.3	256.3	354.6	386.1	379.5	119.5	50.8%	129.8	50.7%	123.2	48.1%
PPL	DR	657.3	716.2	583.4	604.4	658.4	608.7	(52.9)	(8.0%)	(57.8)	(8.1%)	25.3	4.3%
PPL	EE	260.1	283.5	283.5	368.0	400.7	386.1	107.9	41.5%	117.2	41.3%	102.5	36.2%
DAY	DR	240.7	262.4	209.3	214.4	233.5	191.1	(26.3)	(10.9%)	(28.9)	(11.0%)	(18.2)	(8.7%)
DAY	EE	85.3	92.9	92.9	127.2	138.5	127.7	41.9	49.1%	45.6	49.0%	34.8	37.4%
DEOK	DR	202.4	220.3	175.4	212.2	231.2	221.9	9.8	4.8%	10.9	4.9%	46.5	26.5%
DEOK	EE	142.6	155.4	155.4	177.4	193.1	186.0	34.8	24.4%	37.7	24.3%	30.6	19.7%

Table 32 Impact of demand resources: 2024/2025 RPM Base Residual Auction

Scenario 5

		Actual Auction Results		No Offers for DR	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$92.77	145,202.6
	Summer	$28.92	605.6	$92.77	605.6
	Winter	$28.92	605.6	$92.77	605.6
RTO Total			147,478.9		145,808.2
MAAC	Annual	$49.49	64,148.1	$92.77	65,049.7
	Summer	$49.49	52.7	$92.77	52.7
	Winter	$49.49	52.7	$92.77	52.7
MAAC Total			64,200.8		65,102.4
DEOK	Annual	$96.24	2,060.0	$113.38	1,866.4
	Summer	$96.24	0.0	$113.38	0.0
	Winter	$96.24	0.0	$113.38	0.0
DEOK Total			2,060.0		1,866.4
EMAAC	Annual	$54.95	30,670.5	$118.12	30,199.7
	Summer	$54.95	0.0	$118.12	0.0
	Winter	$54.95	0.0	$118.12	0.0
EMAAC Total			30,670.5		30,199.7
DPL South	Annual	$90.64	1,422.0	$118.12	1,402.5
	Summer	$90.64	0.0	$118.12	0.0
	Winter	$90.64	0.0	$118.12	0.0
DPL South Total			1,422.0		1,402.5
BGE	Annual	$73.00	2,671.6	$112.14	2,585.9
	Summer	$73.00	0.0	$112.14	0.0
	Winter	$73.00	0.0	$112.14	0.0
BGE Total			2,671.6		2,585.9

Table 33 Impact of EE: 2024/2025 RPM Base Residual Auction

Scenario 6

		Actual Auction Results		No EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$28.91	139,566.5
	Summer	$28.92	605.6	$28.91	244.1
	Winter	$28.92	605.6	$28.91	244.1
RTO Total			147,478.9		139,810.6
MAAC	Annual	$49.49	64,148.1	$49.49	60,788.8
	Summer	$49.49	52.7	$49.49	18.2
	Winter	$49.49	52.7	$49.49	18.2
MAAC Total			64,200.8		60,807.0
DEOK	Annual	$96.24	2,060.0	$96.24	1,876.1
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		1,876.1
EMAAC	Annual	$54.95	30,670.5	$54.95	28,763.8
	Summer	$54.95	0.0	$54.95	0.0
	Winter	$54.95	0.0	$54.95	0.0
EMAAC Total			30,670.5		28,763.8
DPL South	Annual	$90.64	1,422.0	$90.64	1,322.2
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,322.2
BGE	Annual	$73.00	2,671.6	$73.00	2,293.0
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,293.0

Table 34 Impact of price responsive demand (PRD): 2023/2024 RPM Base Residual Auction

Scenario 7

		Actual Auction Results		No PRD	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$29.30	147,193.0
	Summer	$28.92	605.6	$29.30	605.6
	Winter	$28.92	605.6	$29.30	605.6
RTO Total			147,478.9		147,798.6
MAAC	Annual	$49.49	64,148.1	$51.47	64,428.4
	Summer	$49.49	52.7	$51.47	52.7
	Winter	$49.49	52.7	$51.47	52.7
MAAC Total			64,200.8		64,481.1
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$55.21	30,706.7
	Summer	$54.95	0.0	$55.21	0.0
	Winter	$54.95	0.0	$55.21	0.0
EMAAC Total			30,670.5		30,706.7
DPL South	Annual	$90.64	1,422.0	$90.64	1,436.2
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,436.2
BGE	Annual	$73.00	2,671.6	$96.88	2,793.3
	Summer	$73.00	0.0	$96.88	0.0
	Winter	$73.00	0.0	$96.88	0.0
BGE Total			2,671.6		2,793.3

Table 35 Impact of seasonal products: 2024/2025 RPM Base Residual Auction Scenario 8

		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	$28.92	146,873.3	$32.46	147,147.6
	Summer	$28.92	605.6	$32.46	0.0
	Winter	$28.92	605.6	$32.46	0.0
RTO Total			147,478.9		147,147.6
MAAC	Annual	$49.49	64,148.1	$49.71	64,149.3
	Summer	$49.49	52.7	$49.71	0.0
	Winter	$49.49	52.7	$49.71	0.0
MAAC Total			64,200.8		64,149.3
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$54.97	30,670.5
	Summer	$54.95	0.0	$54.97	0.0
	Winter	$54.95	0.0	$54.97	0.0
EMAAC Total			30,670.5		30,670.5
DPL South	Annual	$90.64	1,422.0	$90.64	1,422.0
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,422.0
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

Table 36 Impact of seasonal matching across LDAs: 2024/2025 RPM Base Residual Auction

Scenario 9

		Actual Auction Results		Seasonal within LDA	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$29.00	146,878.4
	Summer	$28.92	605.6	$29.00	572.6
	Winter	$28.92	605.6	$29.00	572.6
RTO Total			147,478.9		147,451.0
MAAC	Annual	$49.49	64,148.1	$49.71	64,149.3
	Summer	$49.49	52.7	$49.71	20.8
	Winter	$49.49	52.7	$49.71	20.8
MAAC Total			64,200.8		64,170.1
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$54.97	30,670.5
	Summer	$54.95	0.0	$54.97	0.0
	Winter	$54.95	0.0	$54.97	0.0
EMAAC Total			30,670.5		30,670.5
DPL South	Annual	$90.64	1,422.0	$90.64	1,422.0
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,422.0
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

Table 37 RPM imports: 2007/2008 through 2024/2025 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
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6

Table 38 Impact of capacity imports: 2024/2025 RPM Base Residual Auction

Scenario 10

		Actual Auction Results		No Capacity Imports	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$36.00	146,866.9
	Summer	$28.92	605.6	$36.00	605.6
	Winter	$28.92	605.6	$36.00	605.6
RTO Total			147,478.9		147,472.5
MAAC	Annual	$49.49	64,148.1	$49.25	64,119.9
	Summer	$49.49	52.7	$49.25	52.7
	Winter	$49.49	52.7	$49.25	52.7
MAAC Total			64,200.8		64,172.6
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$54.97	30,670.5
	Summer	$54.95	0.0	$54.97	0.0
	Winter	$54.95	0.0	$54.97	0.0
EMAAC Total			30,670.5		30,670.5
DPL South	Annual	$90.64	1,422.0	$90.64	1,422.0
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,422.0
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

Table 39 Impact of combined scenarios 5, 6, 7, 8, 9, 11: 2024/2025 RPM Base Residual Auction

Scenario 11

		Actual Auction Results		Inferior	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$168.38	135,524.0
	Summer	$28.92	605.6	$168.38	0.0
	Winter	$28.92	605.6	$168.38	0.0
RTO Total			147,478.9		135,524.0
MAAC	Annual	$49.49	64,148.1	$168.38	61,795.3
	Summer	$49.49	52.7	$168.38	0.0
	Winter	$49.49	52.7	$168.38	0.0
MAAC Total			64,200.8		61,795.3
DEOK	Annual	$96.24	2,060.0	$243.86	1,661.5
	Summer	$96.24	0.0	$243.86	0.0
	Winter	$96.24	0.0	$243.86	0.0
DEOK Total			2,060.0		1,661.5
EMAAC	Annual	$54.95	30,670.5	$168.38	28,230.3
	Summer	$54.95	0.0	$168.38	0.0
	Winter	$54.95	0.0	$168.38	0.0
EMAAC Total			30,670.5		28,230.3
DPL South	Annual	$90.64	1,422.0	$168.38	1,271.5
	Summer	$90.64	0.0	$168.38	0.0
	Winter	$90.64	0.0	$168.38	0.0
DPL South Total			1,422.0		1,271.5
BGE	Annual	$73.00	2,671.6	$168.38	2,325.1
	Summer	$73.00	0.0	$168.38	0.0
	Winter	$73.00	0.0	$168.38	0.0
BGE Total			2,671.6		2,325.1

Table 40 Impact of including capacity categorically exempt from RPM must offer: 2024/2025 RPM Base Residual Auction

Scenario 12

		Actual Auction Results		Remove Categorically Exempt Offers	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$81.25	145,773.2
	Summer	$28.92	605.6	$81.25	0.0
	Winter	$28.92	605.6	$81.25	0.0
RTO Total			147,478.9		145,773.2
MAAC	Annual	$49.49	64,148.1	$81.25	64,098.5
	Summer	$49.49	52.7	$81.25	0.0
	Winter	$49.49	52.7	$81.25	0.0
MAAC Total			64,200.8		64,098.5
DEOK	Annual	$96.24	2,060.0	$181.49	1,916.4
	Summer	$96.24	0.0	$181.49	0.0
	Winter	$96.24	0.0	$181.49	0.0
DEOK Total			2,060.0		1,916.4
EMAAC	Annual	$54.95	30,670.5	$144.61	29,993.5
	Summer	$54.95	0.0	$144.61	0.0
	Winter	$54.95	0.0	$144.61	0.0
EMAAC Total			30,670.5		29,993.5
DPL South	Annual	$90.64	1,422.0	$364.64	1,268.2
	Summer	$90.64	0.0	$364.64	0.0
	Winter	$90.64	0.0	$364.64	0.0
DPL South Total			1,422.0		1,268.2
BGE	Annual	$73.00	2,671.6	$84.21	2,646.9
	Summer	$73.00	0.0	$84.21	0.0
	Winter	$73.00	0.0	$84.21	0.0
BGE Total			2,671.6		2,646.9

Table 41 Impact of excluding capacity categorically exempt from RPM must offer: 2024/2025 RPM Base Residual Auction

Scenario 13

		Actual Auction Results		Include all Categorically Exempt Offers	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$25.66	144,557.0
	Summer	$28.92	605.6	$25.66	605.6
	Winter	$28.92	605.6	$25.66	605.6
RTO Total			147,478.9		145,162.6
MAAC	Annual	$49.49	64,148.1	$44.00	62,968.4
	Summer	$49.49	52.7	$44.00	52.7
	Winter	$49.49	52.7	$44.00	52.7
MAAC Total			64,200.8		63,021.1
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$44.00	30,015.8
	Summer	$54.95	0.0	$44.00	0.0
	Winter	$54.95	0.0	$44.00	0.0
EMAAC Total			30,670.5		30,015.8
DPL South	Annual	$90.64	1,422.0	$90.64	1,420.7
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,420.7
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

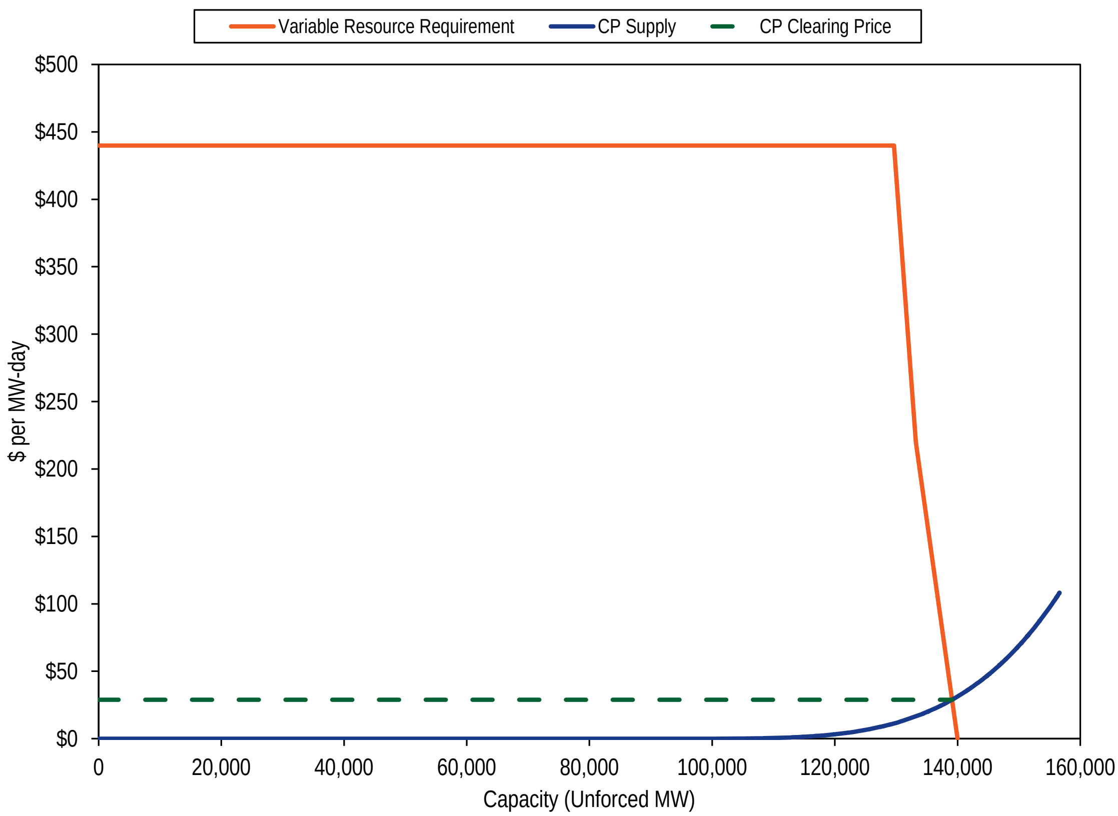
Table 42 Impact of nuclear offers: 2024/2025 RPM Base Residual Auction Scenario 14

		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	$28.92	146,873.3	$28.93	146,860.7
	Summer	$28.92	605.6	$28.93	605.6
	Winter	$28.92	605.6	$28.93	605.6
RTO Total			147,478.9		147,466.3
MAAC	Annual	$49.49	64,148.1	$48.35	64,135.5
	Summer	$49.49	52.7	$48.35	52.7
	Winter	$49.49	52.7	$48.35	52.7
MAAC Total			64,200.8		64,188.2
DEOK	Annual	$96.24	2,060.0	$96.24	2,060.0
	Summer	$96.24	0.0	$96.24	0.0
	Winter	$96.24	0.0	$96.24	0.0
DEOK Total			2,060.0		2,060.0
EMAAC	Annual	$54.95	30,670.5	$49.49	30,710.5
	Summer	$54.95	0.0	$49.49	0.0
	Winter	$54.95	0.0	$49.49	0.0
EMAAC Total			30,670.5		30,710.5
DPL South	Annual	$90.64	1,422.0	$90.64	1,422.0
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,422.0
BGE	Annual	$73.00	2,671.6	$73.00	2,671.6
	Summer	$73.00	0.0	$73.00	0.0
	Winter	$73.00	0.0	$73.00	0.0
BGE Total			2,671.6		2,671.6

Table 43 Impact of combined scenarios 2, 4, 5, 10: 2024/2025 RPM Base Residual Auction Scenario 15

		Actual Auction Results		Combined scenarios 2,4,5,10	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Annual	$28.92	146,873.3	$90.00	142,355.4
	Summer	$28.92	605.6	$90.00	297.8
	Winter	$28.92	605.6	$90.00	297.8
RTO Total			147,478.9		142,653.2
MAAC	Annual	$49.49	64,148.1	$90.00	64,087.6
	Summer	$49.49	52.7	$90.00	20.2
	Winter	$49.49	52.7	$90.00	20.2
MAAC Total			64,200.8		64,107.8
DEOK	Annual	$96.24	2,060.0	$181.21	1,845.4
	Summer	$96.24	0.0	$181.21	0.0
	Winter	$96.24	0.0	$181.21	0.0
DEOK Total			2,060.0		1,845.4
EMAAC	Annual	$54.95	30,670.5	$90.00	30,013.0
	Summer	$54.95	0.0	$90.00	0.0
	Winter	$54.95	0.0	$90.00	0.0
EMAAC Total			30,670.5		30,013.0
DPL South	Annual	$90.64	1,422.0	$90.64	1,349.3
	Summer	$90.64	0.0	$90.64	0.0
	Winter	$90.64	0.0	$90.64	0.0
DPL South Total			1,422.0		1,349.3
BGE	Annual	$73.00	2,671.6	$90.00	2,585.4
	Summer	$73.00	0.0	$90.00	0.0
	Winter	$73.00	0.0	$90.00	0.0
BGE Total			2,671.6		2,585.4

Figure 2 RTO market supply/demand curves: 2024/2025 RPM Base Residual Auction[194] [195]



194 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.

195 The VRR curve excludes incremental demand which cleared in MAAC, EMAAC, DPL South, BGE, and DEOK.

MAAC LDA Market Results

Table 44 shows total MAAC LDA offer data for the 2024/2025 RPM Base Residual Auction. Total internal MAAC LDA unforced capacity, excluding generation winter capacity, of 71,888.0 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 9, MAAC LDA unforced internal capacity increased 858.2 MW from 71,029.8 MW in the 2023/2024 BRA as a result of net generation capacity modifications (206.6 MW), net DR modifications (-396.5 MW), and net EE modifications (1,611.2 MW), the EFORd effect due to higher sell offer EFORds (-557.9 MW), and the DR and EE effect due to a lower load management UCAP conversion factor (-5.2 MW). As shown in Table 11, total internal MAAC unforced winter capacity increased by 23.5 MW for November through April of the 2024/2025 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[196] Total internal MAAC LDA capacity was reduced by FRR commitments of 55.6 MW, resulting in MAAC LDA RPM capacity of 71,871.8 MW. RPM capacity was reduced by 674.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 371.8 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 1,231.9 MW of intermittent resources and 720.8 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 and changes in capacity resource status. Subtracting 433.1 MW of DR and EE not offered and 13.2 MW of unoffered generation winter capacity resulted in available unforced capacity in MAAC LDA of 68,426.9 MW.[197] After accounting for these exceptions, all capacity resources in MAAC LDA were offered in the RPM Auction.

The MAAC LDA import limit was a binding constraint in the 2024/2025 BRA. Of the 64,200.8 MW cleared in MAAC LDA, 55,586.7 MW were cleared in the RTO before MAAC LDA became constrained. Once the constraint was binding, based on the 5,965.0 MW CETL value, only the incremental supply located in MAAC LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 8,614.1 MW cleared,

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196 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

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

which resulted in a clearing price of $49.49 per MW-day, as shown in Figure 5. The clearing price was determined by the intersection of the incremental supply and VRR curve.

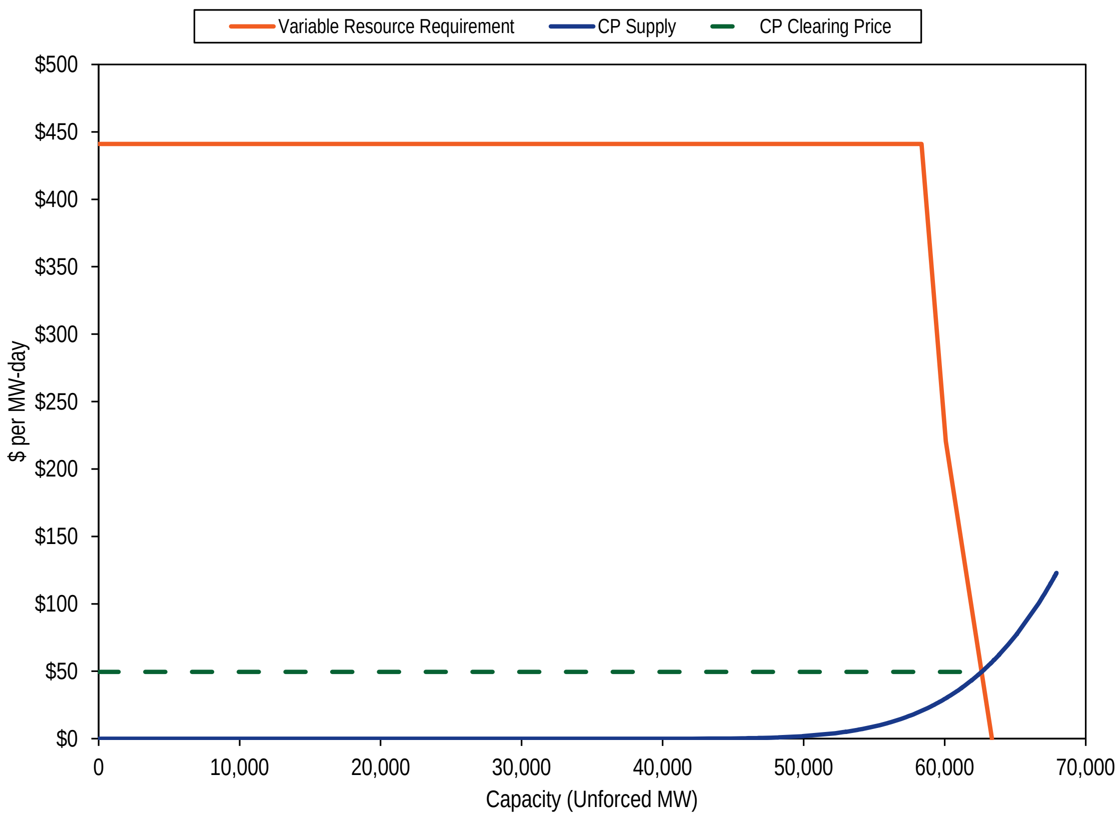
As shown in Table 16, the 60,759.2 MW of cleared generation and DR for MAAC LDA and 5,965.0 MW CETL resulted in a net excess of 3,538.5 MW.

Table and Figure for MAAC LDA

Table 44 MAAC LDA offer statistics: 2024/2025 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	68,372.6	64,957.7		
DR capacity	2,862.1	3,111.2		
EE capacity	3,506.7	3,819.1		
Generation winter capacity	39.4	39.4		
Total internal MAAC LDA capacity	74,780.8	71,927.4		
FRR	(56.1)	(55.6)		
Imports	0.0	0.0		
RPM capacity	74,724.7	71,871.8		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(476.3)	(371.8)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(1,233.3)	(1,231.9)		
Unoffered Capacity Storage Resources	(720.8)	(720.8)		
Unoffered generation winter capacity	(13.2)	(13.2)		
Unoffered DR and EE	(397.6)	(433.1)		
Available	71,209.4	68,426.9	100.0%	100.0%
Generation offered	65,238.2	61,929.7	91.6%	90.5%
DR offered	2,737.3	2,975.2	3.8%	4.3%
EE offered	3,233.9	3,522.0	4.5%	5.1%
Total offered	71,209.4	68,426.9	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 3 MAAC LDA market supply/demand curves: 2024/2025 RPM Base Residual Auction[198]



EMAAC LDA Market Results

Table 45 shows total EMAAC LDA offer data for the 2024/2025 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity, excluding generation winter capacity, of 34,237.4 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 9, EMAAC LDA unforced internal capacity increased 777.1 MW from 33,460.3 MW in the 2023/2024 BRA as a result of net generation capacity modifications (85.5 MW), net DR modifications (-194.2 MW), and net EE modifications (1,051.1 MW), the EFORd effect due to higher sell offer EFORds (-163.0 MW), and the DR and EE effect due to a lower load management UCAP conversion factor (-2.3 MW). As shown in Table 11, total internal

198 The VRR curve is reduced by the CETL and incremental demand which cleared in EMAAC, DPL South and BGE.

EMAAC unforced winter capacity increased by 0.0 MW for November through April of the 2024/2025 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO. Total internal EMAAC LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in EMAAC LDA RPM capacity of 34,237.4 MW. RPM capacity was reduced by 674.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 343.0 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 761.9 MW of intermittent resources and 650.0 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 and changes in capacity resource status. Subtracting 246.7 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 31,561.7 MW. After accounting for these exceptions, all capacity resources in EMAAC LDA were offered in the RPM Auction.

The EMAAC LDA import limit was a binding constraint in the 2024/2025 BRA. Of the 30,670.5 MW cleared in EMAAC LDA, 30,406.2 MW were cleared in the MAAC before EMAAC LDA became constrained. Once the constraint was binding, based on the 8,594.0 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, 264.3 MW cleared, which resulted in a clearing price of $54.95 per MW-day, as shown in Figure 4. The clearing price was determined by the intersection of the incremental supply and VRR curve.

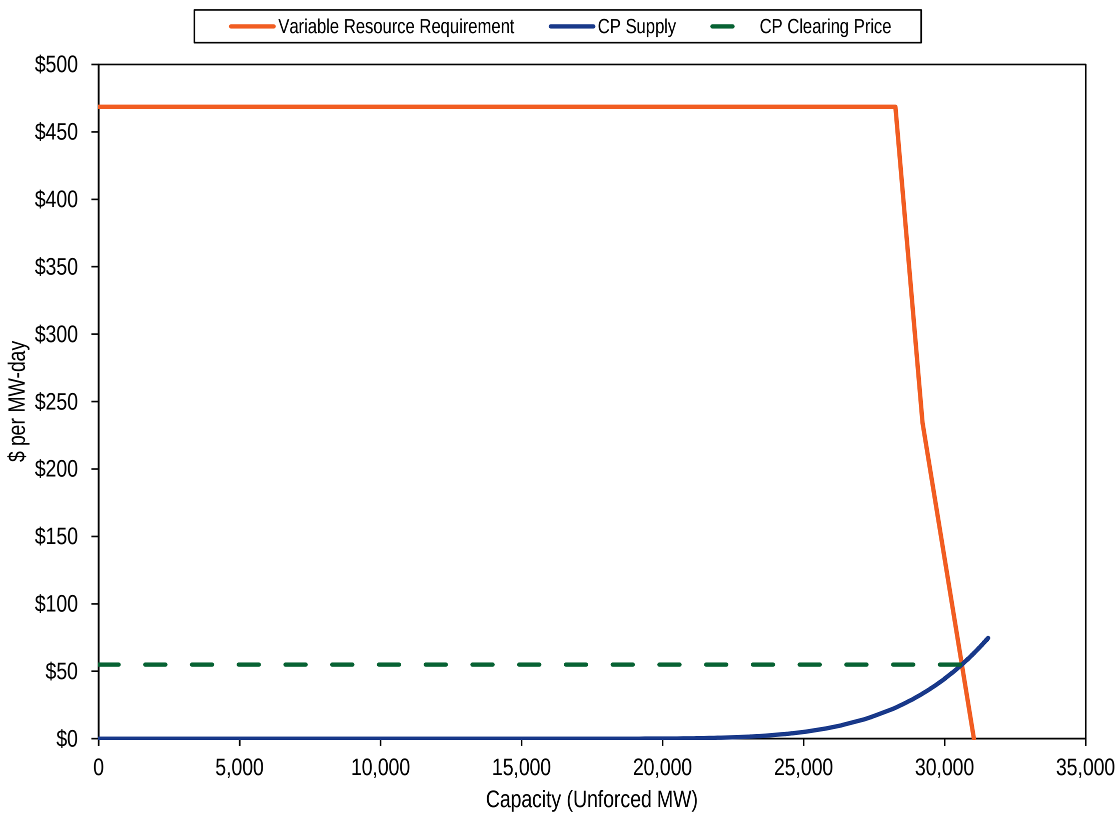
As shown in Table 16, the 28,702.5 MW of cleared generation and DR for EMAAC LDA and 8,594.0 MW CETL resulted in a net excess of 1,919.6 MW.

Table and Figure for EMAAC LDA

Table 45 EMAAC LDA offer statistics: 2024/2025 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	31,869.9	30,701.8		
DR capacity	1,198.2	1,304.5		
EE capacity	2,048.6	2,231.1		
Generation winter capacity	0.0	0.0		
Total internal EMAAC LDA capacity	35,116.7	34,237.4		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	35,116.7	34,237.4		
Exports	(674.0)	(674.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(424.0)	(343.0)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(761.9)	(761.9)		
Unoffered Capacity Storage Resources	(650.0)	(650.0)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(226.5)	(246.7)		
Available	32,380.3	31,561.7	100.0%	100.0%
Generation offered	29,360.0	28,272.9	90.7%	89.6%
DR offered	1,159.3	1,262.1	3.6%	4.0%
EE offered	1,860.9	2,026.7	5.7%	6.4%
Total offered	32,380.3	31,561.7	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 4 EMAAC LDA market supply/demand curves: 2024/2025 RPM Base Residual Auction[199]



DPL South LDA Market Results

Table 46 shows total DPL South LDA offer data for the 2024/2025 RPM Base Residual Auction. Total internal DPL South LDA unforced capacity, excluding generation winter capacity, of 1,902.1 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 9, DPL South LDA unforced internal capacity increased 116.5 MW from 1,785.6 MW in the 2023/2024 BRA as a result of net generation capacity modifications (113.2 MW), net DR modifications (-5.7 MW), and net EE modifications (49.1 MW), the EFORd effect due to higher sell offer EFORds (-40.1 MW), and the DR and EE effect due to a lower load management UCAP conversion factor (0.0 MW). As shown in Table 11, total internal DPL

199 The VRR curve is reduced by the CETL and incremental demand which cleared in DPL South.

South unforced winter capacity increased by 0.0 MW for November through April of the 2024/2025 Delivery Year.

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[200] Total internal DPL South LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in DPL South LDA RPM capacity of 1,902.1 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 329.0 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 109.8 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. Subtracting 14.6 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in DPL South LDA of 1,448.7 MW.[201] After accounting for these exceptions, all capacity resources in DPL South LDA were offered in the RPM Auction.

The DPL South LDA import limit was a binding constraint in the 2024/2025 BRA. Of the 1,422.0 MW cleared in DPL South LDA, 1,321.9 MW were cleared in the EMAAC LDA before DPL South LDA became constrained. Once the constraint was binding, based on the 1,962.0 MW CETL value, only the incremental supply located in DPL South LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 100.1 MW cleared, which resulted in a clearing price of $90.64 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 16, the 1,322.2 MW of cleared generation and DR for DPL South LDA and 1,962.0 MW CETL resulted in a net excess of 145.4 MW.

The results for the 2024/2025 RPM Base Residual Auction were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[202]

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200 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

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

202 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same

PJM calculates the reliability requirement for each LDA prior to the Base Residual Auction as the sum of CETO and projected internal capacity within the LDA. The CETO represents the capacity needed by the LDA to satisfy a 1 in 25 loss of load expectation. The CETO depends on the reliability profile of the existing generation capacity, both inside and outside the LDA, and projected generation capacity expected to be in service by the beginning of the delivery year. The final reliability requirement of the LDA is accurate only if the projected generation capacity for the delivery year matches the offered generation capacity. In the 2024/2025 RPM Base Residual Auction, substantial capacity was assumed by PJM in the CETO and reliability requirement calculations to be in service by the beginning of the delivery year.

The review of actual offers in the 2024/2025 Base Residual Auction revealed a substantial flaw in the design of the capacity market. A significant level of capacity located in the DPL South LDA that PJM had assumed would be offered in the BRA did not offer. PJM's reliability requirement for the DPL South was calculated based on the assumption that the proposed generation capacity resources that had completed PJM's interconnection service agreement at the time of the CETO calculation would be available to satisfy the DPL South LDA's target reliability criteria of less than one loss of load event in 25 years. The inconsistency between the projected generation capacity in DPL South LDA and the actual offers resulted in an overstated CETO and reliability requirement for the DPL South LDA.

Prior to clearing the auction and posting prices, PJM requested that FERC allow PJM to correctly reflect only the actual capacity offers and the associated revised CETO and reliability requirement of the DPL South LDA for the 2024/2025 RPM Base Residual Auction. PJM also requested a tariff change to provide PJM the authority to revise the CETO and reliability requirement of any LDA in the future for similar situations. FERC approved PJM's request, and PJM posted the auction clearing results on February 27, 2023. [203]

revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.

[203] On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.

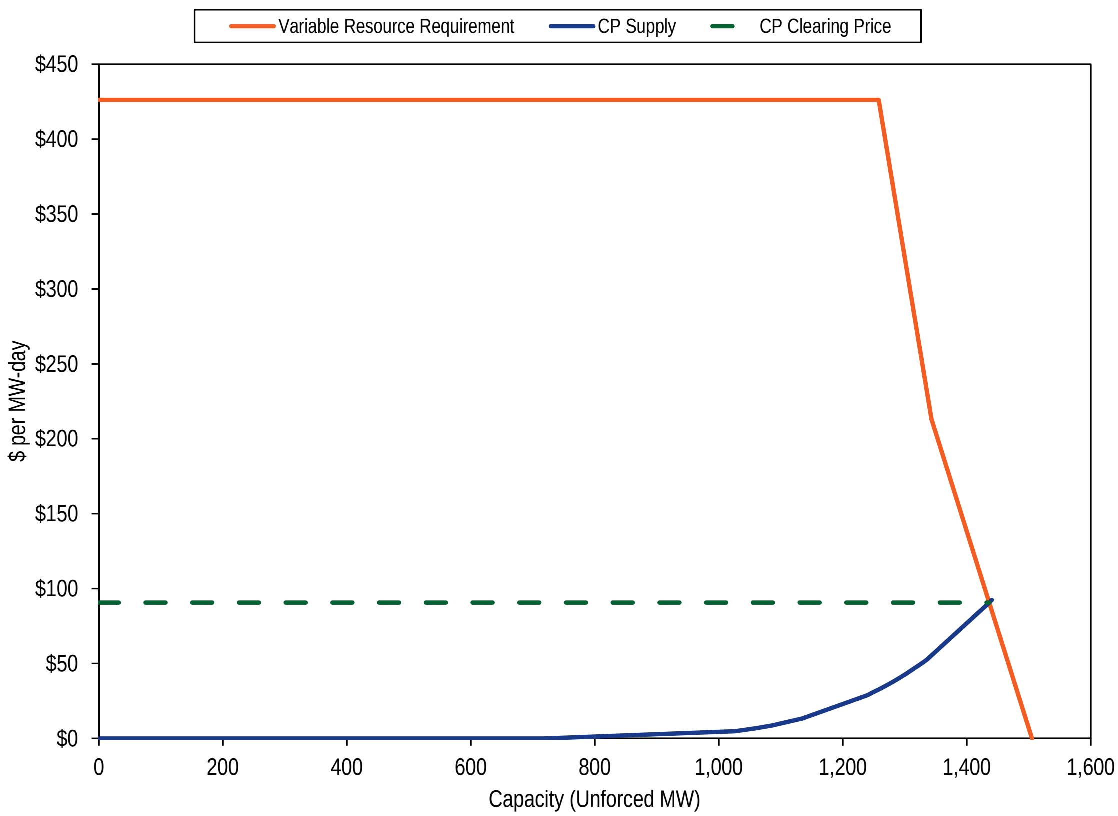
Table and Figure for DPL South LDA

Table 46 DPL South LDA offer statistics: 2024/2025 RPM Base Residual Auction[204]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	1,866.3	1,741.5		
DR capacity	55.4	60.3		
EE capacity	92.0	100.3		
Generation winter capacity	0.0	0.0		
Total internal DPL South LDA capacity	2,013.7	1,902.1		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	2,013.7	1,902.1		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(410.0)	(329.0)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(109.8)	(109.8)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(13.4)	(14.6)		
Available	1,480.5	1,448.7	100.0%	100.0%
Generation offered	1,346.5	1,302.7	90.9%	89.9%
DR offered	42.3	46.0	2.9%	3.2%
EE offered	91.7	100.0	6.2%	6.9%
Total offered	1,480.5	1,448.7	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

204 The total internal DPL South LDA capacity includes available capacity at the time of the auction as defined in PJM's Capacity Exchange system. Queue projects that were not yet accredited or defined to have available capacity in PJM's Capacity Exchange system at the time of the auction are not included in this total.

Figure 5 DPL South LDA market supply/demand curves: 2024/2025 RPM Base Residual Auction[205]



BGE LDA Market Results

Table 47 shows total BGE LDA offer data for the 2024/2025 RPM Base Residual Auction. Total internal BGE LDA unforced capacity, excluding generation winter capacity, of 2,969.7 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 9, BGE LDA unforced internal capacity increased 54.1 MW from 2,915.6 MW in the 2023/2024 BRA as a result of net generation capacity modifications (4.1 MW), net DR modifications (12.7 MW), and net EE modifications (136.6 MW), the EFORd effect due to higher sell offer EFORds (-98.4 MW), and the DR and EE effect due to a lower load management UCAP conversion factor (-0.9 MW). As shown in Table 11, total internal BGE unforced winter capacity increased by 0.0 MW for November through April of the 2024/2025 Delivery Year.

205 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.[206] Total internal BGE LDA capacity was reduced by FRR commitments of 0.0 MW, resulting in BGE LDA RPM capacity of 2,969.7 MW. RPM capacity was reduced by 0.0 MW of exports, 0.0 MW of FRR optional volumes not offered, 0.0 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 4.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 30.4 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 2,935.3 MW.[207] 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 2024/2025 BRA. Of the 2,671.6 MW cleared in BGE LDA, 1,017.5 MW were cleared in the MAAC LDA before BGE LDA became constrained. Once the constraint was binding, based on the 5,397.0 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, 1,654.1 MW cleared, which resulted in a clearing price of $73.00 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 16, the 2,292.2 MW of cleared generation and DR for BGE LDA and 5,397.0 MW CETL resulted in a net excess of 349.5 MW.

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206 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).

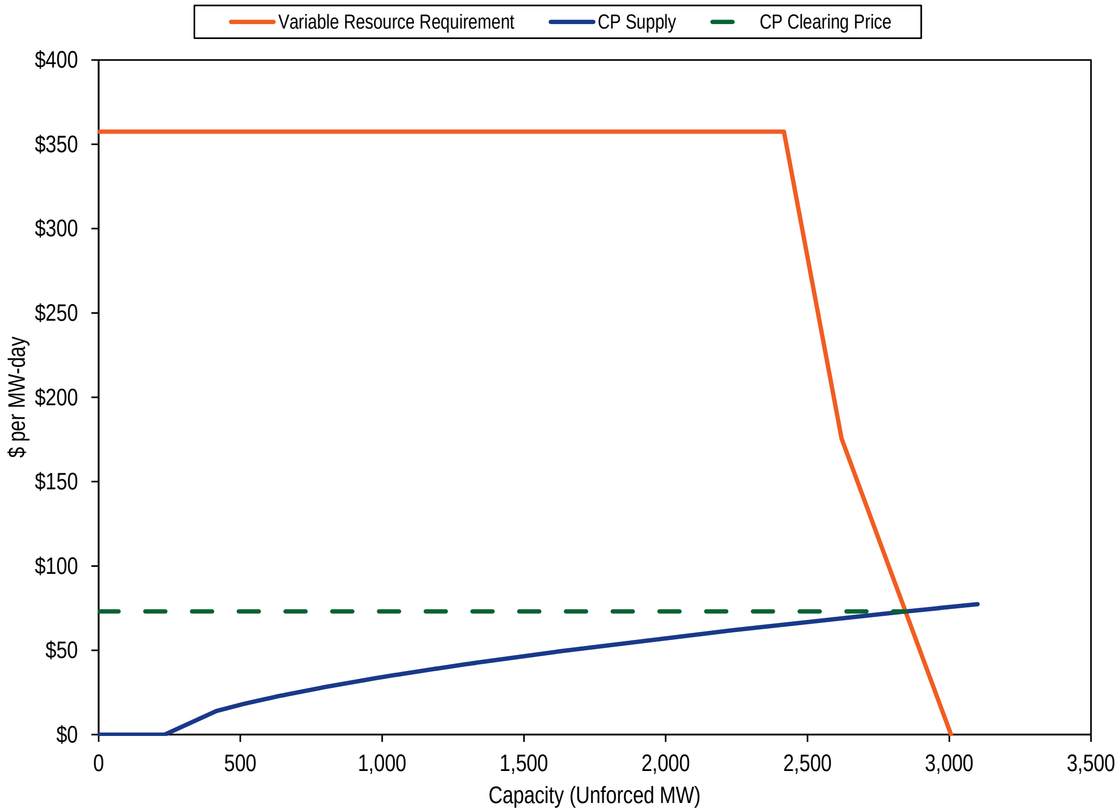
207 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 47 BGE LDA offer statistics: 2024/2025 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	2,634.0	2,329.1		
DR capacity	232.4	247.4		
EE capacity	361.1	393.2		
Generation winter capacity	0.0	0.0		
Total internal BGE LDA capacity	3,227.5	2,969.7		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	3,227.5	2,969.7		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	0.0	0.0		
Unoffered Capacity Storage Resources	(4.0)	(4.0)		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(27.9)	(30.4)		
Available	3,195.6	2,935.3	100.0%	100.0%
Generation offered	2,630.0	2,325.1	82.3%	79.2%
DR offered	211.0	224.1	6.6%	7.6%
EE offered	354.6	386.1	11.1%	13.2%
Total offered	3,195.6	2,935.3	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: 2024/2025 RPM Base Residual Auction[208]



DEOK LDA Market Results

Table 48 shows total DEOK LDA offer data for the 2024/2025 RPM Base Residual Auction. Total internal DEOK LDA unforced capacity, excluding generation winter capacity, of 3,160.5 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 9, DEOK LDA unforced internal capacity decreased 10.2 MW from 3,170.7 MW in the 2023/2024 BRA as a result of net generation capacity modifications (-6.7 MW), net DR modifications (32.1 MW), and net EE modifications (48.1 MW), the EFORd effect due to higher sell offer EFORds (-83.5 MW), and the DR and EE effect due to a lower load management UCAP conversion factor (-0.2 MW). As shown in Table 11, total internal DEOK unforced winter capacity increased by 0.0 MW for November through April of the 2024/2025 Delivery Year.

208 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. Total internal DEOK LDA capacity was reduced by FRR commitments of 863.3 MW, resulting in DEOK LDA RPM capacity of 2,297.2 MW. RPM capacity was reduced by 0.0 MW of exports, 99.8 MW of FRR optional volumes not offered, 0.0 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 41.9 MW of intermittent resources and 0.0 MW of capacity storage resources which were not subject to the CP must offer requirement. Subtracting 48.7 MW of DR and EE not offered and 0.0 MW of unoffered generation winter capacity resulted in available unforced capacity in DEOK LDA of 2,106.8 MW. After accounting for these exceptions, all capacity resources in DEOK LDA were offered in the RPM Auction.

The DEOK LDA import limit was a binding constraint in the 2024/2025 BRA. Of the 2,060.0 MW cleared in DEOK LDA, 1,965.9 MW were cleared in the RTO before DEOK LDA became constrained. Once the constraint was binding, based on the 4,999.0 MW CETL value, only the incremental supply located in DEOK LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 94.1 MW cleared, which resulted in a clearing price of $96.24 per MW-day, as shown in Figure 7. The clearing price was determined by the intersection of the incremental supply and VRR curve.

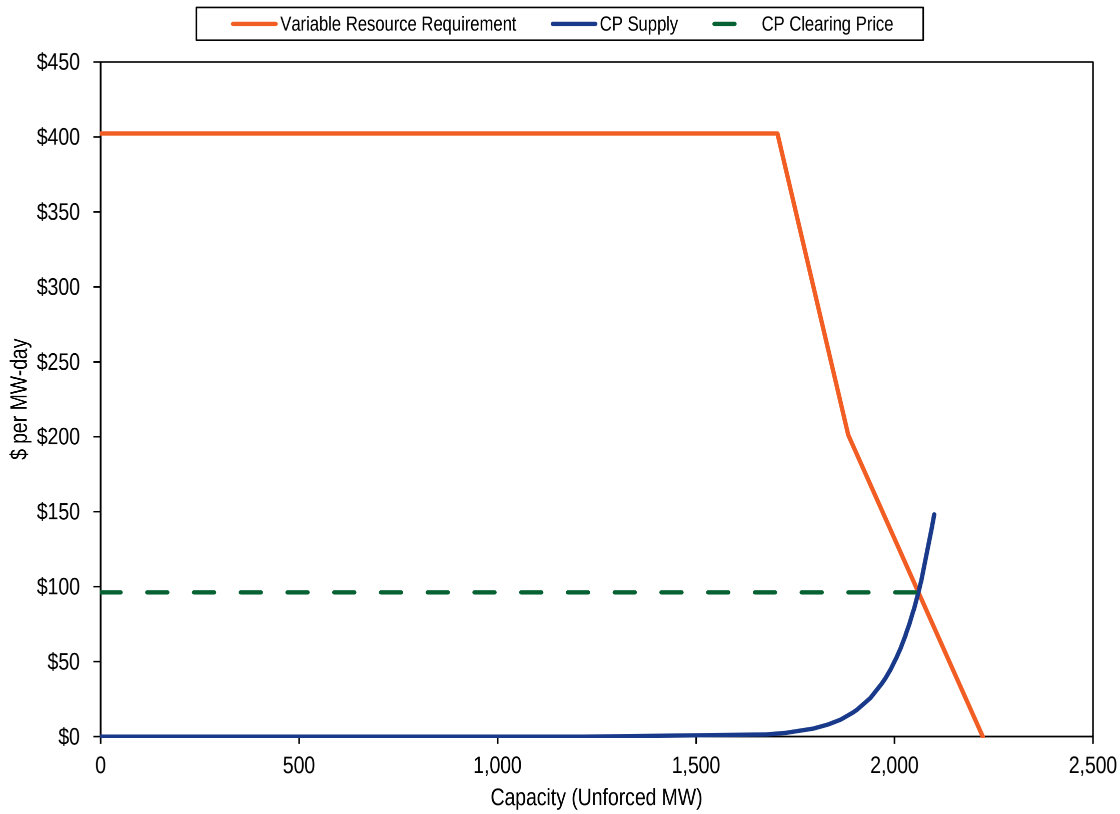
As shown in Table 16, the 1,874.0 MW of cleared generation and DR for DEOK LDA and 4,999.0 MW CETL resulted in a net excess of 850.4 MW.

Table and Figure for DEOK LDA

Table 48 DEOK LDA offer statistics: 2024/2025 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	2,979.7	2,684.3		
DR capacity	248.7	271.0		
EE capacity	188.5	205.2		
Generation winter capacity	0.0	0.0		
Total internal DEOK LDA capacity	3,416.9	3,160.5		
FRR	(954.7)	(863.3)		
Imports	0.0	0.0		
RPM capacity	2,462.2	2,297.2		
Exports	0.0	0.0		
FRR optional	(110.2)	(99.8)		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered Intermittent Resources	(41.9)	(41.9)		
Unoffered Capacity Storage Resources	0.0	0.0		
Unoffered generation winter capacity	0.0	0.0		
Unoffered DR and EE	(44.7)	(48.7)		
Available	2,265.4	2,106.8	100.0%	100.0%
Generation offered	1,875.8	1,682.5	82.8%	79.9%
DR offered	212.2	231.2	9.4%	11.0%
EE offered	177.4	193.1	7.8%	9.2%
Total offered	2,265.4	2,106.8	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	0.0	0.0	0.0%	0.0%

Figure 7 DEOK LDA market supply/demand curves: 2024/2025 RPM Base Residual Auction[209]



209 The VRR curve is reduced by the CETL.

Attachment A

Clearing Algorithm for RPM Base Residual Auction

The 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.[1] 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 cooptimizes 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 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

1 OATT Attachment DD § 5.12(a).

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 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 rather than a fully flexible offer. If any such inflexible offers are marginal or close to marginal, PJM's market solution algorithm relaxes the minimum level of those offers and re-solves the optimization, allowing those offers to clear below the specified minimum level. Any resource that, as a result, cleared at a MW level below the specified minimum level, is paid uplift for the difference between cleared MW and the minimum level, at the clearing price. The solution method does not consider the additional cost of uplift payments as part of the 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 an uplift payment. In the MMU's approach, the RPM algorithm explicitly compares solutions with uplift against solutions without uplift 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 2024/2025 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 within 0.002 percent of the corresponding total MW cleared under PJM's method. The total MW cleared for the entire RTO using the MMU's algorithm is within 0.0001 percent of the total MW cleared under PJM's method. The clearing prices using the PJM's approach were within 0.04 percent of the corresponding 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.

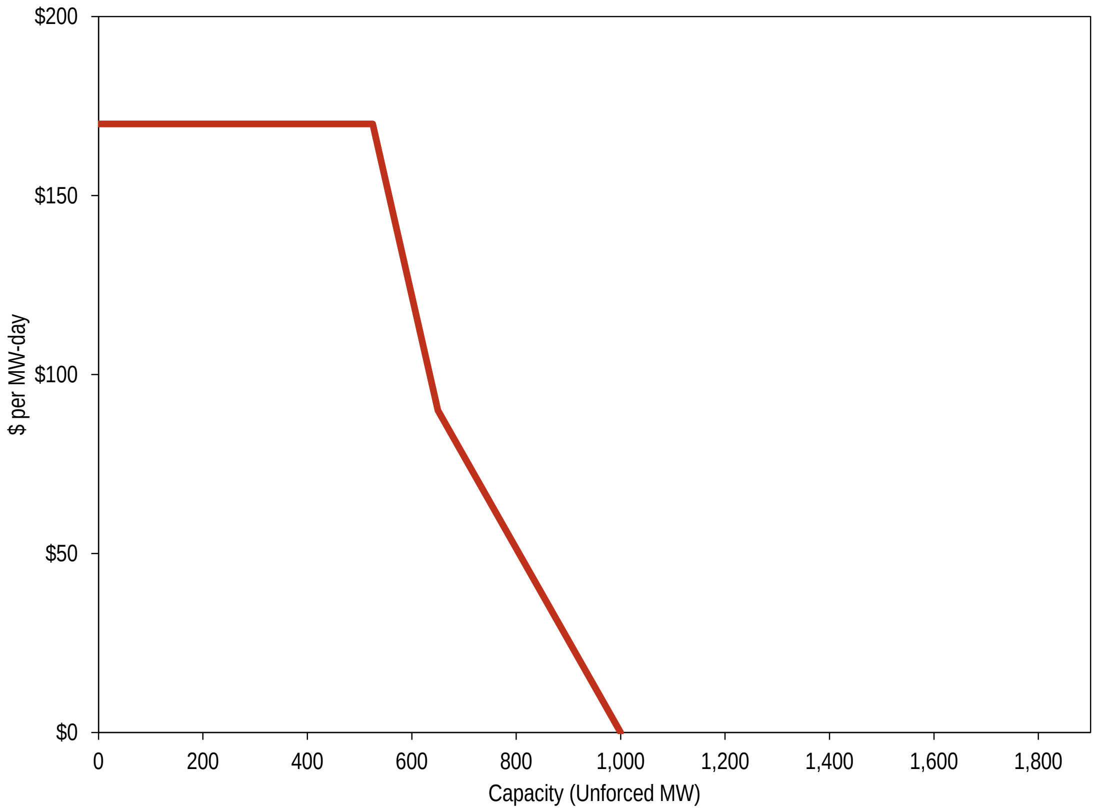
The MMU recommends improving the RPM solution method related to uplift payments. The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift payments in the objective function.

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 8 and Figure 9 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.[2]

Figure 1 Variable resource requirement curve: child LDA



2 For simplicity, the Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint are not included.

Figure 2 Nested variable resource requirement curve: parent LDA

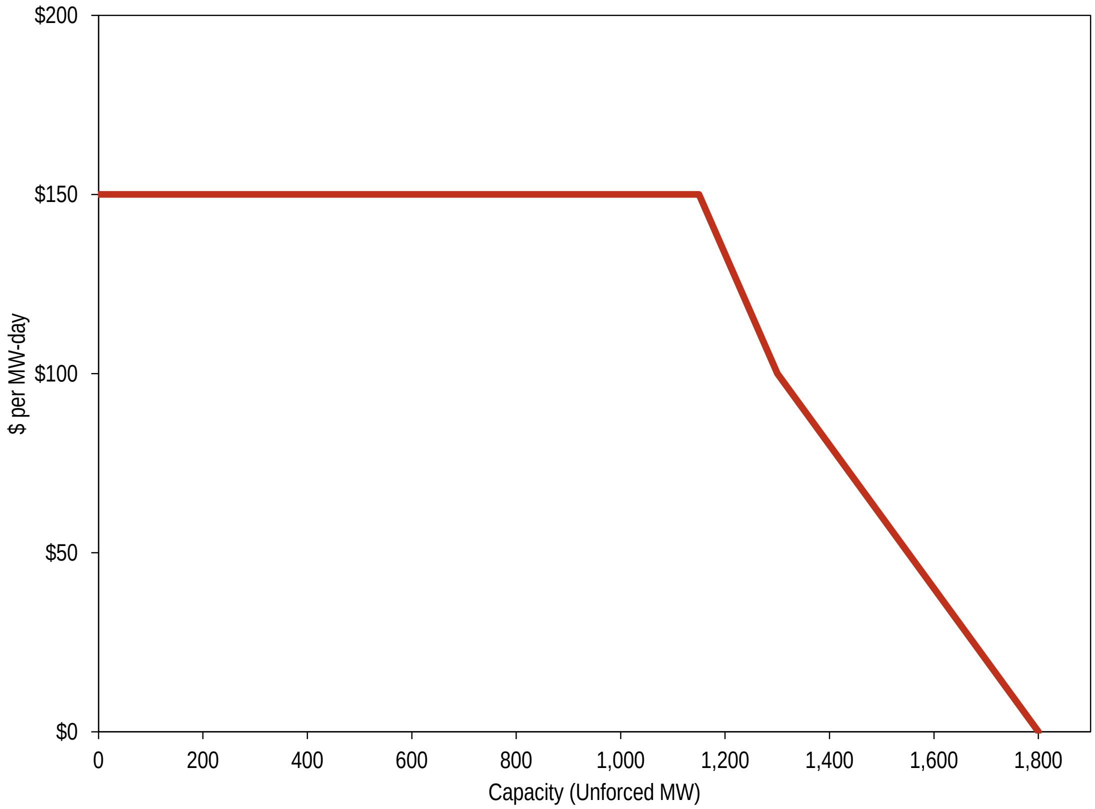


Figure 10 and Figure 11 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is $120.00.

Figure 3 Optimal solution for scenario 1: child LDA

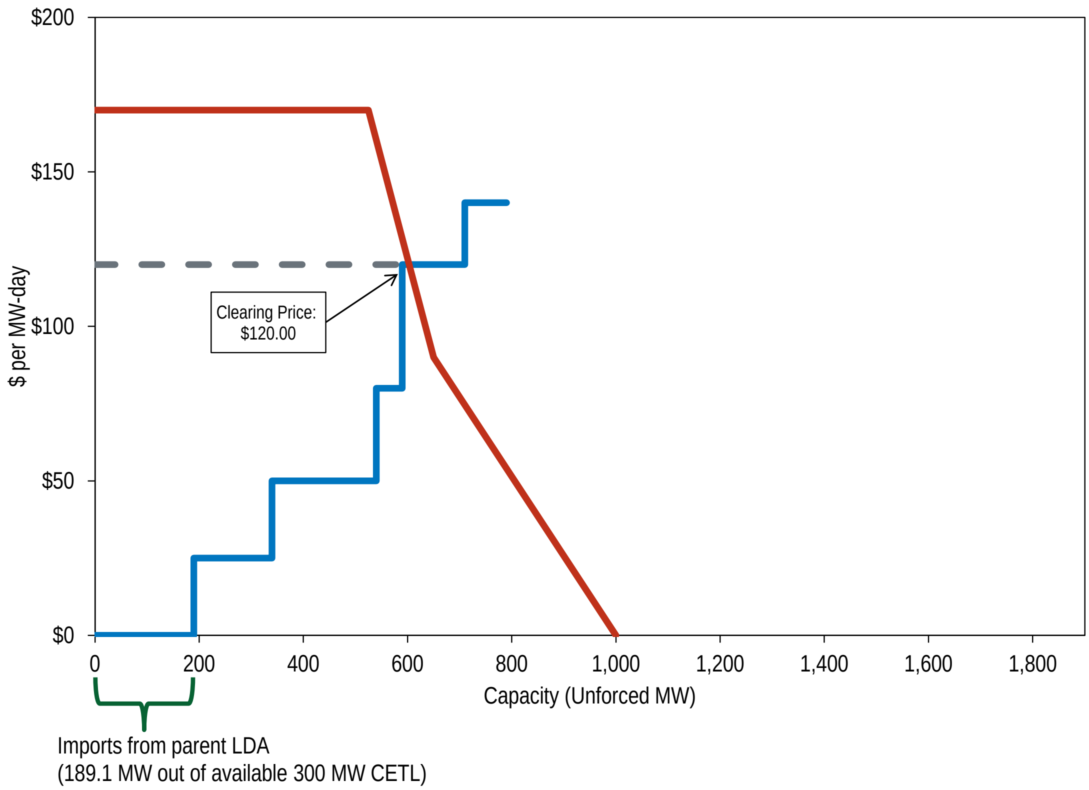


Figure 4 Optimal solution for scenario 1: Parent LDA

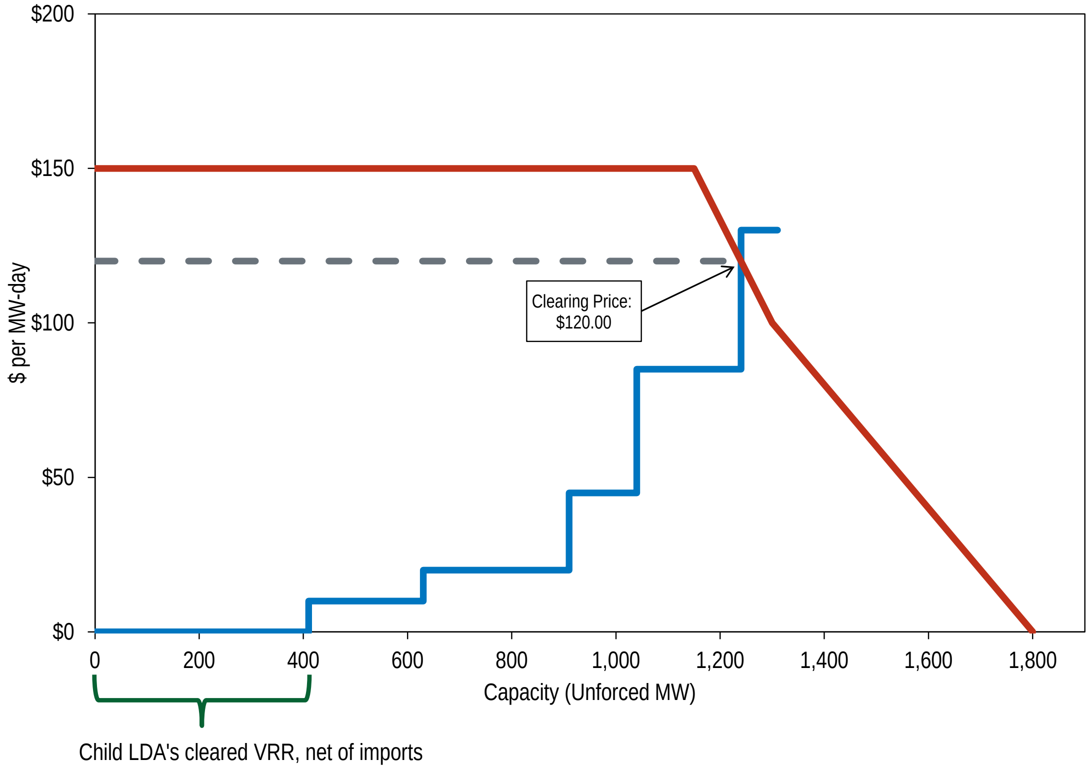


Figure 12 and Figure 13 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA 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 5 Optimal solution for scenario 2: Child LDA

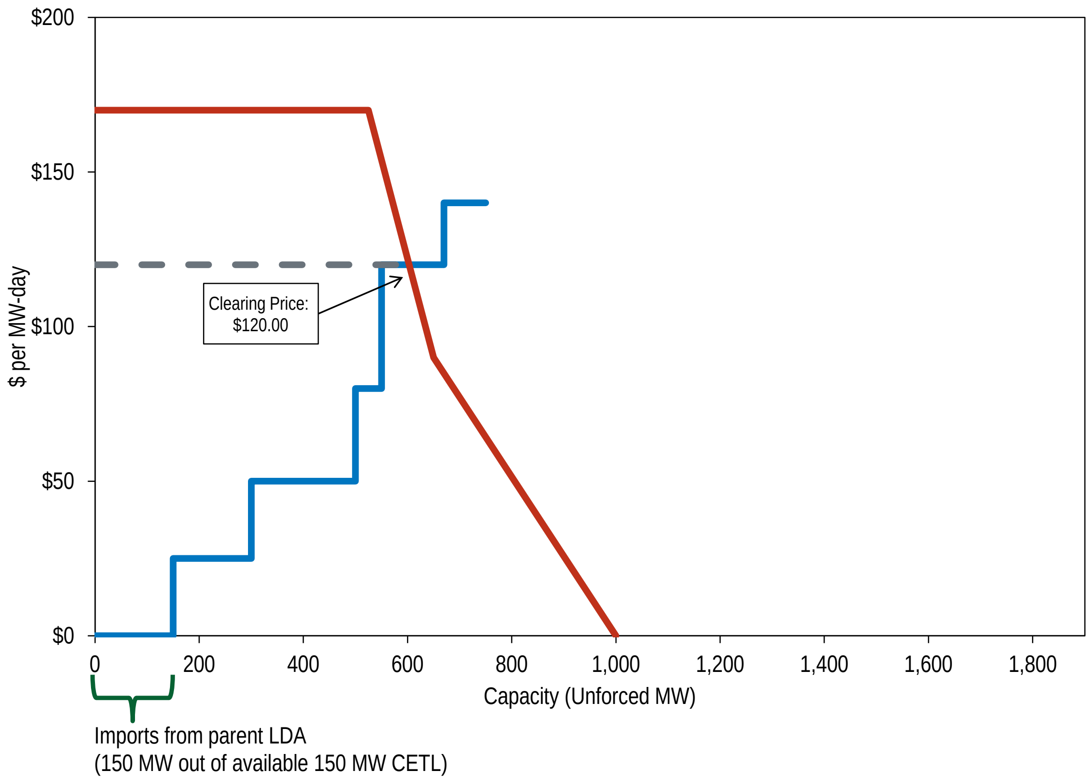


Figure 6 Optimal solution for scenario 2: Parent LDA