Monitoring Analytics

Analysis of the 2025/2026 RPM Base Residual Auction Part D

The Independent Market Monitor for PJM

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Introduction

This report, Part D of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a fourth set of sensitivity analyses of the nineteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) for the 2025/2026 Delivery Year which was held from July 17 to 23, 2024. The sensitivities in Part C and Part D also address the implications of market design changes for the 2026/2027 BRA. The MMU prepares a comprehensive report for each RPM Base Residual Auction. In this case, rather than waiting until all sensitivities are completed, the MMU will present the results of sensitivities as they are completed in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months. The MMU will provide a comprehensive report later. The results reported by the MMU are not forecasts or predictions of the outcome of the 2026/2027 BRA.

The capacity market is getting tighter. The result will be higher capacity market prices. In a well designed market, capacity market prices reflect the underlying supply and demand fundamentals. The results of the 2025/2026 BRA illustrate the amplified impact of not getting the details of the market design right when the market is tight. The MMU analysis shows that while a significant increase in capacity market payments was based on the fundamentals, market design and market power issues resulted in actual capacity market payments that were approximately twice as high as needed in the 2025/2026 auction. Without significant changes to key details of the market design, prices in the 2026/2027 auction will be significantly higher than in the 2025/2026 auction and also not consistent with market fundamentals.[1]

The market design details that had a significant impact on the results of the 2025/2026 auction were: the shift from the EFORd availability metric to the ELCC availability metric; the impact of withholding by categorically exempt resources; the impact of using summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources; the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve; and the use of Gross CONE rather than 1.5 times Net CONE as the maximum price in the market.

An increase in demand will further tighten the market, and prices in the next capacity auction will reflect both that increase and the market design issues. The MMU analysis

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[1] *See* reports analyzing the 2025/2026 RPM Base Residual Auction, "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (Sep. 20, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (Oct. 15, 2024), "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (Nov. 6, 2024). These reports can be found at <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>.

shows that with a 5.0 percent increase in load forecast over the load forecast used in the 2025/2026 auction and Gross CONE as the maximum price, total payments would increase by more than 80 percent over the actual 2025/2026 payments, to $28,514,872,062, even if a CT is used as a reference resource and RMR capacity is fully included in the supply curve. (Scenario 32 in Part C.) That level of increase is in significant part the result of using Gross CONE rather than 1.5 times Net CONE as the maximum price on the capacity market demand curve (VRR curve).

A goal of market design should be to be consistent and predictable and transparent. A consistent, predictable and transparent design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. New supply requires competitive incentives and a stable investment environment. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. The objective of the market design should also be markets that are transparent and understandable to market participants and to regulators. The capacity market design should be as simple as possible to meet its objectives. The current capacity market design does not meet these standards.

The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on the VRR curves that were used in the 2025/2026 BRA but will not be used in the 2026/2027 RPM BRA. The Part C report addresses the impacts of PJM's initially posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, and two load growth scenarios. The reported sensitivity results are not predictions or forecasts of the outcome of the 2026/2027 BRA. The sensitivity results show the direction and magnitude of the impacts on capacity market revenues of the proposed market design changes if they had been implemented in the 2025/2026 BRA. Actual conditions could change for the 2026/2027 BRA including changes in supply, in demand and in offer behavior.

The Part C report addresses, explains and quantifies the combined impact of specific critical market design choices in the 2025/2026 BRA that were identified in Part A and further analyzed in Part B, and market design choices for the 2026/2027 BRA. The Part C report and the Part D report focus on the potential impacts of market design choices for the 2026/2027 BRA, currently expected to be run in July 2025, and particularly the impact of increases in forecast load. This Part D report, when compared with the results in the Part C report, demonstrates the significant impact of using the higher of Gross CONE and 1.5 times Net CONE as the maximum price on the VRR curve when there is forecast load growth above that used in the 2025/2026 BRA. The scenarios analyzed in Part D include use of a CT as the reference resource, a maximum price defined by 1.5 times Net CONE, and two load growth scenarios, combined with the separate and combined impacts on market outcomes of the three identified MMU proposed changes: the impact of the exclusion of two reliability must run (RMR) plants from the capacity market supply curve;

the impact of using summer ratings rather than winter ratings for CC and CT resources; and the impact of withholding by categorically exempt resources.[2]

The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. The posted preliminary RTO wide peak load forecast for the 2026/2027 BRA was 157,197.0 MW, 3,313.9 MW or 2.2 percent higher than the peak load forecast for 2025/2026 BRA. The MMU analyzed two peak load forecast scenarios. The MMU scenarios include an increase in the peak load forecast to 157,730.1 MW, an increase of 3,847.1 MW or 2.5 percent, over the preliminary peak load forecast for 2025/2026 BRA and an increase in the peak load forecast to 161,577.2 MW, an increase of 7,694.2 MW or 5.0 percent, over the preliminary peak load forecast used in the 2025/2026 BRA.

Recognizing that the quantitative results are estimates, based on explicitly stated assumptions, the results show the direction and magnitude of the combined impacts of the identified factors in the PJM capacity market design.

The results reported in Part D can be used to evaluate potential market design changes for the 2026/2027 BRA.[3]

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve with a maximum price of 1.5 times Net CONE based on updated calculations of Net CONE for a CT as the reference resource, a forward net revenue offset, and a 2.5 percent increase in the peak load forecast, the capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the marginal ELCC based accreditation had included higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,165,738,398, a decrease of $5,521,308,959, or 37.6 percent, compared to the actual results (Scenario 50).

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2 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.

3 See "Consultation With Members Regarding Future 205 Filing on Capacity Market," Special Markets and Reliability Committee, November 7, 2024 <https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx>.

In summary, holding everything else constant, if the 2025/2026 RPM BRA had been cleared using a VRR curve with a maximum price of 1.5 times Net CONE based on updated calculations of Net CONE for a CT as the reference resource, a forward net revenue offset, and a 5.0 percent increase in the peak load forecast, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, the marginal ELCC based accreditation had included higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,963,442,312, an increase of $1,276,394,955, or 8.7 percent, compared to the actual results (Scenario 54).

The significance of the Part D results is highlighted by a comparison with the Part C results. With an increase in the peak load forecast of 5.0 percent, the market would clear at the maximum price, even with the MMU's three identified proposed changes. As a result, the use of Gross CONE rather than 1.5 times Net CONE as the maximum price on the VRR curve, without the MMU's three identified proposed changes, would result in RPM revenues of $26,772,578,885, (Scenario 31) while the use of 1.5 times Net CONE would result in RPM revenues of $15,963,442,312 (Scenario 54). With an increase in the peak load forecast of 5.0 percent, the use of Gross CONE as the maximum price would result in an increase in RPM revenues of $10,809,136,573, or 67.7 percent, compared to the use of 1.5 times Net CONE together with the MMU's three identified proposed changes.

The Part C results show that if the maximum price were set at Gross CONE for a CT and the peak load forecast increased by 2.5 percent, RPM revenues would increase by $12,085,531,528 or 82.3 percent, to $26,772,578,885 (Scenario 27). With the MMU's three identified proposed changes, RPM revenues would decrease by $1,213,109,681 or 8.3 percent, to $13,473,937,677 (Scenario 30).

The Part C results show that if the maximum price were set at Gross CONE for a CT and the peak load forecast increased by 5.0 percent, RPM revenues would increase by $12,085,531,528 or 82.3 percent, to $26,772,578,885 (Scenario 31). With the MMU's three identified proposed changes, RPM revenues would increase by $13,827,824,704 or 94.1 percent, to $28,514,872,062 (Scenario 34).

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 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.[4] Under the hourly 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.

The MMU recognizes that implementation of the recommendations in this report would require rule changes in some cases.

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.[5] 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. 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, measured in UCAP.

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

4 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>.

5 The locational element of the PJM Capacity Market is limited to the recognition of different LDAs which were initially defined by transmission zones but now also include subzones. However the PJM Capacity Market is not fully locational because it treats all capacity within an LDA as equivalent rather than recognizing the impacts of internal transmission constraints.

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.

There are currently two important gaps in the market power rules for the PJM Capacity Market. Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include pumped storage hydroelectric, impoundment hydroelectric, flywheel, and battery. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory. Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources also do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power. The result is to increase the clearing prices above the competitive level. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps, like all other capacity resources.

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. As in all other markets, the competitive offer in the capacity market is the marginal cost of capacity. A competitive offer in the capacity market is equal to net ACR.[6]

All participants to which the three pivotal supplier (TPS) test was applied (in the RTO, BGE, and DOM 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.[7] [8]

Based on the data and this analysis in Part A, Part B and Part C, the MMU concludes that the results of the 2025/2026 RPM Base Residual Auction were significantly affected by flawed market design decisions including PJM's ELCC approach, by the failure to offer categorically exempt resources including, in some cases, the exercise of market power through the withholding of categorically exempt resources, and the exercise of market power through high offers from demand resources, and by the exclusion from supply of the defined RMR resources. The BRA prices do not solely reflect supply and demand fundamentals but also reflect, in significant part, PJM decisions about the definition of supply and demand. The auction results were not solely the result of the introduction of the ELCC approach and do in part reflect the tightening of supply and demand conditions

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6 174 FERC ¶ 61,212 ("March 18th Order") at 65.

7 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.

8 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).

in the PJM Capacity Market. PJM's ELCC filing that created many of these issues was approved by FERC.[9]

Based on the data and the analysis in Part C, the MMU concludes that prices based on market fundamentals would have been significantly higher in the 2025/2026 BRA than in the 2024/2025 BRA, but that PJM's design choices resulted in the prices in the 2025/2026 BRA approximately twice as high (112.1 percent) as supported by the fundamentals (Scenario 16).

Based on the data and the analysis in Part C and Part D, the MMU concludes that there is a significant risk of much higher capacity market prices in the 2026/2027 BRA than in the 2025/2026 BRA if the forecast peak load is from to 2.5 to 5.0 percent higher than the forecast peak load used in the 2025/2026 BRA, primarily as a result of PJM's use of Gross CONE as the maximum price rather than 1.5 times Net CONE. The MMU concludes that use of 1.5 times Net CONE as the maximum price, with the MMU's three identified proposed changes, and with 5.0 percent higher forecast load, would result in an increase of $1,276,394,955 over the actual revenues in the 2025/2026 BRA (Scenario 54). The MMU concludes that use of Gross CONE as the maximum price, not including the MMU's three identified proposed changes, and with 5.0 percent higher forecast load, would result in an increase of $12,085,531,528 over the actual revenues in the 2025/2026 (Scenario 31). That is the increase that would result from PJM's proposal. That increase would be excessive and would not be based on market fundamentals.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are

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9 186 FERC ¶ 61,080 (January 30, 2024).

reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

Recommendations

The recommendations in Part A and Part B are related primarily to the results of the sensitivity analyses presented in both Part A and Part B. The recommendations in Part C include the recommendations in Part A and Part B and add additional recommendations. Part D emphasizes the recommendation that 1.5 times Net CONE be used as the maximum price on the VRR curve rather than Gross CONE.

The MMU recommends that the must offer rule in the capacity market apply to all capacity resources.[10] Prior to the implementation of the capacity performance design, all existing capacity resources, except DR, were subject to the RPM must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM 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 RPM must offer requirement is also to ensure equal access to the transmission system through capacity interconnection rights (CIRs). 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.[11] The same logic should be applied to categorically exempt intermittent and storage capacity resources. The failure to apply the RPM must offer requirement will create increasingly significant market design issues, artificially high capacity prices, and market power issues in the capacity market as the level of capacity from intermittent and capacity storage resources increases. The failure to apply the RPM must offer requirement consistently could also result in very significant changes in supply from auction to auction that 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

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10 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>.

11 The MMU's position is that CIRs should be returned to the pool of available transmission at the time of a resource's retirement and not held for one year.

must offer requirement for capacity resources. Holding aside the market power issue, the capacity market can work only if both are enforced.

The reasons for the categorical exemption of intermittent resources and storage to date were based on the seasonality of the resources and on PJM's imposition of performance assessment interval (PAI) penalties for nonperformance when performance was not physically possible, e.g. PAI penalties to solar for not producing at night. Neither applies to all the exempt resources and neither is a good reason to exempt these resources. As the role of categorically exempt intermittents and storage grows it is essential to reestablish the must offer obligation for all resources. The inclusion of a must offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform. This is not the removal of performance penalties from wind and solar resources and it is not discriminatory. It is a recognition of the reality that wind and solar resources are not capable of performing at defined times. The capacity market has included balanced must buy and must sell obligations from its inception. The current rules can and should be changed to restore that balance. PJM's recent suggestion that as part of extending the must offer obligation, the market seller offer caps must be changed for categorically exempt resources based on the risk imposed by PJM's illogical imposition of PAI penalties on such resources when they cannot perform (e.g. solar at night) is not consistent with the actual risks faced by such resources rather than the risks unnecessarily created by PJM's PAI design.[12]

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM does treat RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part. There are times when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has

12 Market Implementation Committee (MIC). Comments by Adam Keech (December 4, 2024).

committed to the construction of new transmission that will eliminate the price signal when complete. The relevant rules can and should be changed.

The MMU recommends that the ELCC be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance. Specifically, in the short run the MMU recommends that capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the Gross CONE in ICAP terms for a CT to the Gross CONE in UCAP terms be the ELCC based on winter ratings.

The MMU recommends that the maximum price on the VRR curve be set to 1.5 times the Net CONE rather than the greater of Gross CONE and 1.75 times Net CONE.

Summary of Results

Cleared generation and DR for the entire RTO of 134,224.2 MW resulted in a reserve margin of 18.6 percent and a net excess of 870.9 MW over the reliability requirement adjusted for FRR and PRD of 133,353.3 MW.[13] Net excess is defined as cleared MW of capacity and DR minus the reliability requirement, adjusted for FRR and PRD.

The net excess unforced capacity in the 2025/2026 RPM Base Residual Auction is based on the ELCC approach and the net excess unforced capacity in the 2024/2025 RPM Base Residual Auction is based on the prior EFORd approach. Net excess is significantly affected by the method used to define UCAP. Under the ELCC approach, UCAP is the derated ICAP based on the ELCC Accredited UCAP Factor for the resource (ICAP * AUCAP Factor). Under the EFORd approach, UCAP is ICAP adjusted by the unit forced outage rate (ICAP * (1 – EFORd)). The supply and demand balance in the PJM system will

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

appear much tighter using the ELCC approach than the EFORd approach for exactly the same resources.

Net excess decreased 7,215.9 MW from the net excess of 8,086.8 MW in the 2024/2025 RPM Base Residual Auction. This comparison overstates the reduction in net excess because the net excess for the 2024/2025 BRA was in EFORd terms while the net excess for the 2025/2026 BRA was in ELCC terms.

The intersection of the supply curve and the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $269.92 per MW-day for the rest of RTO.

Table 2 through Table 6 show the summary of the revenue impacts of the scenarios analyzed in Part D. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part A ("Part A") and Part B ("Part B") are based on VRR curves that are not applicable for the 2026/2027 RPM Base Residual Auction. The Part C report addressed the impacts of PJM's posted VRR curve parameters for the 2026/2027 BRA based on the actual data from the 2025/2026 BRA, the scenarios from Part A and Part B, use of a CT as the reference resource, and two load growth scenarios. The results of the scenarios presented in the Analysis of the 2025/2026 RPM Base Residual Auction Part C ("Part C") are based on VRR curves using the higher of Gross CONE and Net CONE times a multiplier. The results of the scenarios presented in this Part D ("Part D") report are based on the VRR curves applicable for 2026/2027 RPM Base Residual Auction using only Net CONE times a multiplier rather than the higher of Gross CONE and a multiplier of Net CONE. The differences between the results of Part C and Part D demonstrate the significant impact of using Gross CONE rather than Net CONE as the maximum price on the VRR curve. The results of individual scenarios are not strictly additive. The combined results of multiple scenarios are shown for scenarios that address multiple results simultaneously. The quantitative results are estimates. The report makes explicit when the quantitative results depend on assumptions. Even in those cases, the quantitative results are correct as to direction and order of magnitude.

The RPM Revenue column shows the revenues that resulted from the defined scenario only. The RPM Revenue Change column shows the difference between the actual RPM total revenues and the total RPM revenues that resulted from the defined scenario. A positive number means that the existing market design elements in the defined scenario resulted in an increase in RPM revenues compared to the MMU recommendation. A negative number means that the existing market design elements in the defined scenario resulted in a decrease in RPM revenues compared to the MMU recommendation. The Percent Change columns show the percent change in RPM revenues for the defined scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the defined scenario. The Actual to Scenario Percent column shows the difference between the revenues under the defined scenario and the actual auction results as a percent of the revenues under the actual auction results.

In Scenarios 35, 36, 37 and 38 (Table 2) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.0 * Net CONE rather than the higher of 1.0 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.0 * Net CONE ($224.50 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[14] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[15] The MW quantities are set at 98.9 percent of the reliability requirement for point A, 101.6 percent of the reliability requirement for point B and 105.8 percent of the reliability requirement for point C.[16]

Figure 1 shows the RTO VRR curve for Scenario 35 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 2 shows the impact on RPM revenues for Scenario 35. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.0 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,656,613,126, a decrease of $5,030,434,231, or 34.3 percent, compared to the actual results (Scenario 35). From another perspective, the actual 2025/2026 VRR curve resulted in a 52.1 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.0 multiplier for Net CONE and a forward net revenue offset (Scenario 35).

Table 2 shows the impact on RPM revenues for Scenario 36. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the

14 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

15 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

16 Ibid.

2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 35, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,143,618,135, a decrease of $6,543,429,222, or 44.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in an 80.4 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 36).

Table 2 shows the impact on RPM revenues for Scenario 37. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 35, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $7,941,726,044, a decrease of $6,745,321,314, or 45.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 84.9 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 37).

Table 2 shows the impact on RPM revenues for Scenario 38. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 35, the MW of capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,071,959,881, a decrease of $8,615,087,476, or 58.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 35, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 141.9 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 38).

In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[17] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[18] The MW quantities are the same as Scenario 35.

Figure 1 shows the RTO VRR curve for Scenario 39 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 3 shows the impact on RPM revenues for Scenario 39. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,922,689,454, a decrease of $4,764,357,903, or 32.4 percent, compared to the actual results (Scenario 39). From another perspective, the actual 2025/2026 VRR curve resulted in a 48.0 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues

17 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

18 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

would have been had PJM cleared the auction using a CT as the reference resource, a 1.5 multiplier for Net CONE and a forward net revenue offset (Scenario 39).

Table 3 shows the impact on RPM revenues for Scenario 40. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 39, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,710,479,295, a decrease of $5,976,568,062, or 40.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 68.6 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 40).

Table 3 shows the impact on RPM revenues for Scenario 41. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 39, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,036,975,859, a decrease of $6,650,071,498, or 45.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 82.7 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 41).

Table 3 shows the impact on RPM revenues for Scenario 42. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 39, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the

2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,725,957,280, a decrease of $7,961,090,078, or 54.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 39, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in an 118.4 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 42).

In Scenarios 43, 44, 45 and 46 (Table 4) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.75 * Net CONE rather than the higher of 1.75 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.75 times Net CONE ($392.88 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[19] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at the 0.75 times Net CONE.[20] The MW quantities are the same as Scenario 35 and Scenario 39.

Table 1 shows the price coordinates used for the point A of the VRR curves in the 2025/2026 BRA and identified scenarios. In the 2025/2026 BRA, the price coordinate for RTO was $451.61 per MW-day which is the higher of 2025/2026 RTO Gross CONE calculated using CT as the reference resource, and 1.5 times 2025/2026 RTO Net CONE using an historical net revenue offset. For Scenarios 36 through 46, the price coordinate for RTO is the identified multiplier times the 2026/2027 RTO Net CONE calculated using CT as the reference resource and forward net revenue offset.

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19 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

20 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

Figure 1 shows the RTO VRR curve for Scenario 43 and the actual VRR curve used for the 2025/2026 RPM Base Residual Auction.

Table 4 shows the impact on RPM revenues for Scenario 43. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.75 multiplier for Net CONE rather than the higher of Gross CONE and a multiplier for Net CONE, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $11,582,638,741, a decrease of $3,104,408,617, or 21.1 percent, compared to the actual results (Scenario 43). From another perspective, the actual 2025/2026 VRR curve resulted in a 26.8 percent increase in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a CT as the reference resource, a 1.75 multiplier for Net CONE and a forward net revenue offset (Scenario 43).

Table 4 shows the impact on RPM revenues for Scenario 44. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 43, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $9,942,592,479, a decrease of $4,744,454,879, or 32.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 47.7 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been had the capacity of the RMR resources been included in the supply curve at $0 per MW-day (Scenario 44).

Table 4 shows the impact on RPM revenues for Scenario 45. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 43, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $8,287,591,005, a decrease of $6,399,456,353, or 43.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 77.2 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been had the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction and had marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction (Scenario 45).

Table 4 shows the impact on RPM revenues for Scenario 46. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 43, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $6,442,190,933, a decrease of $8,244,856,424, or 56.1 percent, compared to the actual results. From another perspective, if in addition to Scenario 43, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 128.0 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been if the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction and if the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction (Scenario 46).

Figure 1 RTO VRR Curves: Actual, Scenario 35, Scenario 39 and Scenario 43

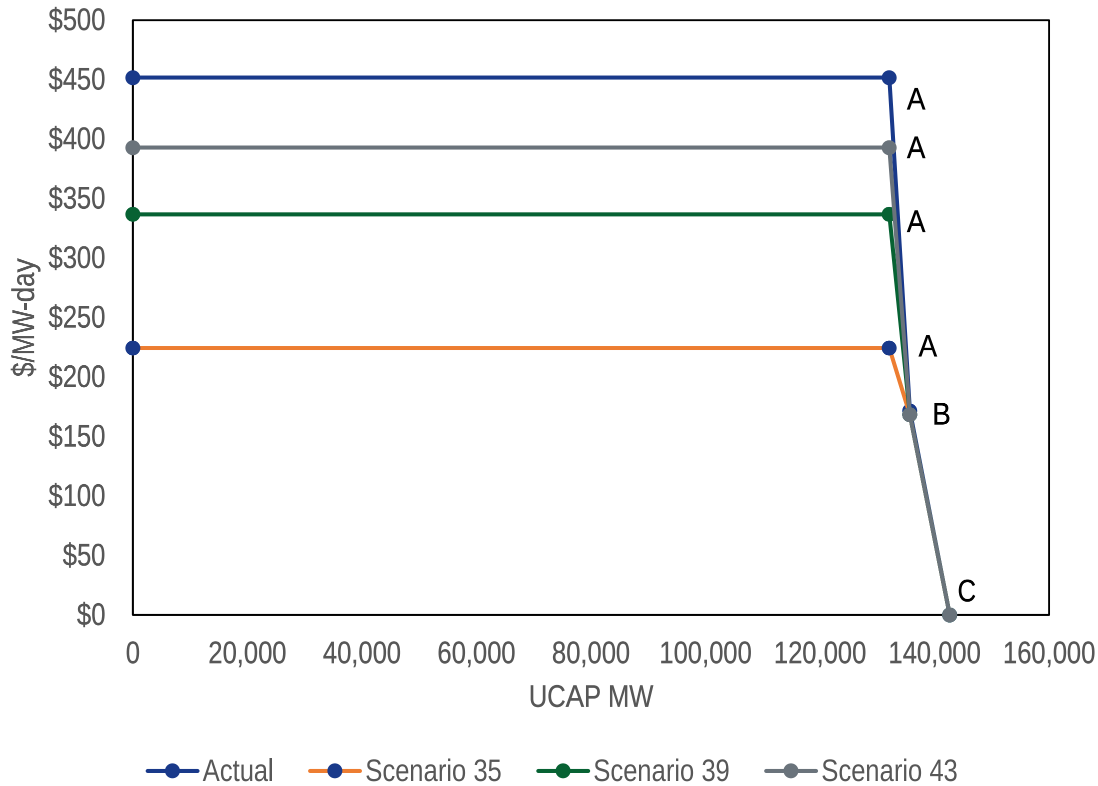

Table 1 Price coordinates used for Point A of the VRR Curve in the 2025/2026 BRA and scenarios

	2025/2026 BRA Max (Gross CONE,1.5*Net CONE) ($/MW-day)	Scenarios 35,36,37,38 1.0*Net CONE for 2026/2027 BRA ($/MW-day)	Scenarios 39,40,41,42 1.5*Net CONE for 2026/2027 BRA ($/MW-day)	Scenarios 43,44,45,46 1.75*Net CONE for 2026/2027 BRA ($/MW-day)
RTO	$451.61	$224.50	$336.75	$392.88
MAAC	$456.19	$292.92	$439.38	$512.61
EMAAC	$466.32	$376.91	$565.37	$659.60
SWMAAC	$466.35	$162.86	$244.29	$285.01
PSEG	$496.46	$415.56	$623.35	$727.24
PS-NORTH	$496.46	$415.56	$623.35	$727.24
DPL-SOUTH	$461.66	$278.03	$417.05	$486.56
PEPCO	$466.35	$271.56	$407.35	$475.24
ATSI	$444.26	$230.72	$346.07	$403.75
ATSI-CLEVELAND	$444.26	$230.72	$346.07	$403.75
COMED	$450.48	$345.41	$518.12	$604.47
BGE	$466.35	$54.16	$81.24	$94.78
PPL	$438.47	$336.60	$504.90	$589.05
DAY	$444.26	$170.83	$256.24	$298.95
DEOK	$444.26	$201.93	$302.90	$353.38
DOM	$444.26	$116.06	$174.09	$203.10

Summary Results Tables

Table 2 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Scenario Impact: RPM Revenue Change ($ per Delivery Year)	Percent Change: Scenario to Actual	Percent Change: Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
35	VRR curve based on 1.00 times net CONE calculated using forward E&AS offset	$9,656,613,126	$5,030,434,231	52.1%	(34.3%)
36	Scenario 35 and RMR resources	$8,143,618,135	$6,543,429,222	80.4%	(44.6%)
37	Scenario 35 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$7,941,726,044	$6,745,321,314	84.9%	(45.9%)
38	Scenario 35 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,071,959,881	$8,615,087,476	141.9%	(58.7%)

Table 3 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Scenario Impact: RPM Revenue Change ($ per Delivery Year)	Percent Change: Scenario to Actual	Percent Change: Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
39	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$9,922,689,454	$4,764,357,903	48.0%	(32.4%)
40	Scenario 39 and RMR resources	$8,710,479,295	$5,976,568,062	68.6%	(40.7%)
41	Scenario 39 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,036,975,859	$6,650,071,498	82.7%	(45.3%)
42	Scenario 39 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,725,957,280	$7,961,090,078	118.4%	(54.2%)

Table 4 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	Scenario Impact: RPM Revenue Change ($ per Delivery Year)	Percent Change: Scenario to Actual	Percent Change: Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
43	VRR curve based on 1.75 times net CONE calculated using forward E&AS offset	$11,582,638,741	$3,104,408,617	26.8%	(21.1%)
44	Scenario 43 and RMR resources	$9,942,592,479	$4,744,454,879	47.7%	(32.3%)
45	Scenario 43 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$8,287,591,005	$6,399,456,353	77.2%	(43.6%)
46	Scenario 43 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$6,442,190,933	$8,244,856,424	128.0%	(56.1%)

Table 5 and Table 6 show the results of selected scenarios with higher forecasted peak loads than used in the 2025/2026 BRA. The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. The posted preliminary RTO wide peak load forecast for the 2026/2027 BRA was 157,196.98 MW, 3,313.9 MW or 2.2 percent higher than the peak load forecast for 2025/2026 BRA.[21] PJM is currently revising their peak load forecast for the 2025/2026 and 2026/2027 Delivery Years following a substantial number of Large Load Adjustment requests received from LSEs and EDCs.[22] The revised 2025/2026 load forecast will be effective for the 2025/2026 Third Incremental Auction expected to be conducted in February 2025. PJM has indicated that the proposed industrial and data center load spread across eleven transmission zones, but mainly concentrated in Dominion and AEP Transmission Zones, is the primary reason for the expected higher demand in the immediate future.[23] PJM estimated that the preliminary accepted requests added up to approximately 9,000 MW for 2025 and approximately 12,000 MW for 2026.[24]

The MMU analyzed two scenarios with higher forecasted peak loads. Scenarios 47, 48, 49 and 50 shows the impact on RPM revenues due to 2.5 percent higher forecasted peak load or 3,847.1 MW higher than used in the 2025/2026 BRA. Scenarios 51, 52, 53 and 54 shows the impact on RPM revenues due to 5.0 percent higher forecasted peak load or 7,694.2 MW higher than used in the 2025/2026 BRA.

Scenario 47, Scenario 48, Scenario 49 and Scenario 50 in Table 5 show the results of Scenarios 39, 40, 41, and 42 from Table 3 with 2.5 percent higher forecasted peak load. In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher

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21 PJM published the peak load forecast as part of the Planning Period Parameters for the 2026/2027 BRA, previously scheduled for December 4 to 10, 2024, and now delayed for approximately six months.

22 See Load Forecast 2025: Potential Model Improvements, Assumptions Review, presented at Load Analysis Subcommittee Meeting <https://www.pjm.com/-/media/committees-groups/subcommittees/las/2024/20240919/20240919-item-04---forecast-model-updates.ashx> (September 19, 2024)

23 See Load Adjustment Requests Summary for 2025 Load Forecast - Preliminary, presented at Planning Committee Meeting <https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20241203/20241203-item-07----large-load-adjustment-requests-summary.ashx> (December 2, 2024)

24 The approximate MW for accepted requests were deduced from the stacked area plots presented by PJM. See Load Adjustment Requests Summary for 2025 Load Forecast – Preliminary, presented at Load Analysis Subcommittee Meeting at Slide 9 <https://www.pjm.com/-/media/committees-groups/subcommittees/las/2024/20241125/20241125-item-05---preliminary-load-adjustment-requests-summary.ashx> (November 25, 2024)

of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[25] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[26] The MW quantities are the same as Scenario 35.

Table 5 shows the impact on RPM revenues for Scenario 47 which is Scenario 39 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and 1.5 times Net CONE, and with 2.5 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $14,992,263,281, an increase of $305,215,923, or 2.1 percent, compared to the actual results (Scenario 47). From another perspective, the actual 2025/2026 VRR curve resulted in a 2.0 percent decrease in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been under Scenario 47.

Table 5 shows the impact on RPM revenues for Scenario 48 which is Scenario 40 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 47, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,233,162,290, a decrease of $2,453,885,067, or 16.71 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 20.1 percent increase in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been under Scenario 48.

Table 5 shows the impact on RPM revenues for Scenario 49 which is Scenario 41 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing

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25 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx (January 13, 2023). Forward E&AS revenues provided by PJM.

26 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 47, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $12,724,537,456, a decrease of $1,962,509,901, or 13.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in an 15.4 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 49.

Table 5 shows the impact on RPM revenues for Scenario 50, which is Scenario 42 from Table 3 with 2.5 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 47, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been 9,165,738,398, a decrease of $5,521,308,959, or 37.6 percent, compared to the actual results. From another perspective, if in addition to Scenario 47, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in an 60.2 percent increase in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 50.

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
47	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$14,992,263,281	($305,215,923)	(2.0%)	2.1%
48	Scenario 47 and RMR resources	$12,233,162,290	$2,453,885,067	20.1%	(16.7%)
49	Scenario 47 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$12,724,537,456	$1,962,509,901	15.4%	(13.4%)
50	Scenario 47 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$9,165,738,398	$5,521,308,959	60.2%	(37.6%)

Scenario 51, Scenario 52, Scenario 53 and Scenario 54 in Table 6 show the results of Scenarios 39, 40, 41, and 42 from Table 3 with 5.0 percent higher forecasted peak load. In Scenarios 39, 40, 41 and 42 (Table 3) the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve based on a Combustion Turbine (CT) as the reference resource rather than a CC and using 1.5 * Net CONE rather than the higher of 1.5 * Net CONE and Gross CONE, in combination with scenarios 2, 3 and 4 from Part A. The maximum price (point A) is set at 1.5 times Net CONE ($336.75 per UCAP MW-day for the Rest of RTO) for the reference CT resource.[27] Net CONE for the CT is calculated using forward net revenues. The price for point B is set at 0.75 times Net CONE.[28] The MW quantities are the same as Scenario 35.

Table 6 shows the impact on RPM revenues for Scenario 51 which is Scenario 39 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If the 2025/2026 RPM BRA had been cleared using a VRR curve based on a CT as the reference resource, a forward net revenue offset, a 1.5 multiplier for Net CONE rather than the higher of Gross CONE and 1.5 times Net CONE, and with 5.0 percent higher forecasted peak load, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,667,694,486, an increase of $1,980,647,128, or 13.5 percent,

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27 CT Gross CONE from Final Default CONE Values. See MIC Special Session – Default ACR Values <https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230113-special/item-03---final-updated-of-default-cone-values.ashx> (January 13, 2023). Forward E&AS revenues provided by PJM.

28 See "PJM Manual 18: PJM Capacity Market," § 3.3 Parameters of the Variable Resource Requirement, Rev. 59 (June 27, 2024).

compared to the actual results (Scenario 51). From another perspective, the actual 2025/2026 VRR curve resulted in an 11.9 percent decrease in 2025/2026 RPM BRA revenues compared to what RPM revenues would have been under Scenario 51.

Table 6 shows the impact on RPM revenues for Scenario 52 which is Scenario 40 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM BRA were $14,687,047,358. If, in addition to Scenario 51, the capacity of the RMR resources in the BGE LDA had been included in the supply curve at $0 per MW-day in the 2025/2026 RPM BRA, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $16,872,370,463, an increase of $2,185,323,105, or 14.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day resulted in a 13.0 percent decrease in RPM revenues for the 2025/2026 RPM Base Residual Auction compared to what RPM revenues would have been under Scenario 52.

Table 6 shows the impact on RPM revenues for Scenario 53 which is Scenario 41 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 51, marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the 2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $17,549,723,556, an increase of$2,862,676,198, or 19.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day and marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources, resulted in a 16.3 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 53.

Table 6 shows the impact on RPM revenues for Scenario 54, which is Scenario 42 from Table 3 with 5.0 percent higher forecasted peak load. Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2025/2026 RPM Base Residual Auction were $14,687,047,358. If, in addition to Scenario 51, the MW capacity categorically exempt from the RPM must offer requirement that did not offer had been offered in the 2025/2026 RPM Base Residual Auction, if marginal ELCC based accreditation considered higher winter generation capacity ratings for CC and CT resources in the 2025/2026 RPM Base Residual Auction, if the capacity of the RMR resources in the BGE LDA been included in the supply curve at $0 per MW-day in the

2025/2026 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2025/2026 RPM Base Residual Auction would have been $15,963,442,312, an increase of $1,276,394,955, or 8.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 51, the fact that the RMR resources in the BGE LDA were not included in the supply curve at $0 per MW-day, marginal ELCC based accreditation did not consider higher winter generation capacity ratings for CC and CT resources and the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 8.0 percent decrease in RPM revenues for the 2025/2026 RPM BRA compared to what RPM revenues would have been under Scenario 54.

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue Change ($ per Delivery Year)	Scenario to Actual	Actual to Scenario
0	Actual results	$14,687,047,358	NA	NA	NA
51	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	$16,667,694,486	($1,980,647,128)	(11.9%)	13.5%
52	Scenario 51 and RMR resources	$16,872,370,463	($2,185,323,105)	(13.0%)	14.9%
53	Scenario 51 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$17,549,723,556	($2,862,676,198)	(16.3%)	19.5%
54	Scenario 51 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,963,442,312	($1,276,394,955)	(8.0%)	8.7%

Table 7 through Table 11 show the 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 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 MW. A negative number means that the specific scenario resulted in an increase in cleared MW. The percent columns show the percent change in RPM cleared MW for the specific scenario from two perspectives. The Scenario to Actual Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined scenario. The Actual to Scenario Percent column shows the difference between the MW under the defined scenario and the defined baseline as a percent of the MW under the defined baseline.

Table 7 shows the impact on the cleared UCAP MW for Scenarios 35 through 38.

Table 8 shows the impact on the cleared UCAP MW for the auction for Scenarios 39 through 42.

Table 10 shows the impact on the cleared UCAP MW for the auction for Scenarios 43 through 46.

Table 11 shows the impact on the cleared UCAP MW for Scenarios 47 through 50.

Table 11 shows the impact on the cleared UCAP MW for Scenarios 51 through 54.

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: CC Reference Resource; 1.0 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
35	VRR curve based on 1.00 times net CONE calculated using forward E&AS offset	135,431.4	252.6	0.2%	(0.2%)
36	Scenario 35 and RMR resources	136,996.7	(1,312.7)	(1.0%)	1.0%
37	Scenario 35 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,340.4	(6,656.4)	(4.7%)	4.9%
38	Scenario 35 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,335.4	(7,651.4)	(5.3%)	5.6%

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.5 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
39	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,457.1	226.9	0.2%	(0.2%)
40	Scenario 39 and RMR resources	137,080.4	(1,396.4)	(1.0%)	1.0%
41	Scenario 39 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,440.4	(6,756.4)	(4.7%)	5.0%
42	Scenario 39 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,391.8	(7,707.8)	(5.4%)	5.7%

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.75 * Net CONE; Forward Net Revenue in VRR curve

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
43	VRR curve based on 1.75 times net CONE calculated using forward E&AS offset	135,530.5	153.5	0.1%	(0.1%)
44	Scenario 43 and RMR resources	137,143.9	(1,459.9)	(1.1%)	1.1%
45	Scenario 43 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,516.5	(6,832.5)	(4.8%)	5.0%
46	Scenario 43 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	143,389.7	(7,705.7)	(5.4%)	5.7%

Table 10 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 2.5 Percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
47	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,604.8	79.2	0.1%	(0.1%)
48	Scenario 47 and RMR resources	137,195.6	(1,511.6)	(1.1%)	1.1%
49	Scenario 47 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,706.4	(7,022.4)	(4.9%)	5.2%
50	Scenario 47 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,245.0	(8,561.0)	(5.9%)	6.3%

Table 11 Scenario summary for 2025/2026 RPM Base Residual Auction: CT Reference Resource; 1.50 * Net CONE; Forward Net Revenue in VRR curve; 5.0 percent Higher Forecasted Peak Load

		Scenario Impact			
				Percent Change	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP Change (MW)	Scenario to Actual	Actual to Scenario
0	Actual results	135,684.0	NA	NA	NA
51	VRR curve based on 1.50 times net CONE calculated using forward E&AS offset	135,604.8	79.2	0.1%	(0.1%)
52	Scenario 51 and RMR resources	137,270.0	(1,586.0)	(1.2%)	1.2%
53	Scenario 51 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,780.8	(7,096.8)	(5.0%)	5.2%
54	Scenario 51 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,389.1	(8,705.1)	(6.0%)	6.4%