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

The Independent Market Monitor for PJM

February 4, 2025

Introduction

This report, Part F of what will be a comprehensive report, prepared by the Independent Market Monitor for PJM (IMM or MMU), presents a sixth 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 F are focused on the implications of the maximum price and minimum price agreed upon by the Governor of Pennsylvania and PJM ("Agreement").[1] The MMU presents the results of these sensitivities in order to provide information to stakeholders that is relevant to decision making about the 2026/2027 BRA, now scheduled for July 9 to 15, 2025, and specifically about the Agreement. The results reported by the MMU are not forecasts or predictions of the outcome of the 2026/2027 BRA.

The Part F report addresses the impacts of using a maximum price of $325/MW-day in UCAP terms and a minimum price of $175/MW-day in UCAP terms and the 5.0 percent increase load growth in all scenarios. In each case, Part F shows the separate and combined impacts on market outcomes of the three identified MMU proposed changes: the inclusion of the two reliability must run (RMR) plants in the capacity market supply curve; the use of winter ratings rather than summer ratings for thermal resources; and the requirement to offer for categorically exempt resources.[2] The Agreement and the method of implementation both matter.

The basic conclusion is that, if implemented consistent with the MMU implementation approach, the Agreement would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented. [3] This calculation compares the results of

[1] *See* Commonwealth of Pennsylvania, "What Industry Leaders, Lawmakers, and Consumer Advocates Are Saying About Governor Shapiro's Action to Save Consumers Over $21 Billion in Utility Charges," (January 31, 2025) <https://www.pa.gov/governor/newsroom/2025-press-releases/-industry-leaders--lawmakers-consumer-adv-saying-about-shapiro-s.html> and also; Email to PJM Members "PA Governor Shapiro Complaint – PJM Notice of Consultation (January 28, 2025).

[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] The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE

MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA. There are more details in this Part F.

The current definition of the price at Point B on the VRR curve is .75 times Net CONE. Based on the information available, the Agreement does not define Point B. The MMU recommends that the price at Point B be defined as .75 times the defined maximum price and that definition is incorporated in Part F. This is the most logical interpretation of the price at Point B under the stated Agreement terms. The maximum price is interpreted as Net CONE given that the Agreement replaces the various CONE values for Point A with a defined price. Point B remains part of the VRR curve unless Point B falls below the minimum price. The price at Point C is the $175/MW-day minimum price defined in the Agreement.

Under the defined VRR curve for the 2025/2026 BRA, the corresponding 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 106.8 percent of the reliability requirement for point C.[4] [5] Although the Agreement does not define the MW points, the MMU recommends that the MW points remain as defined in the VRR curve.

The scenarios in Part F do not explicitly model the minimum price because the minimum price is not a binding constraint in any scenario.

The purpose of Part F is to facilitate a comprehensive review of the implications of the maximum price and minimum price together with additional design choices and to show the implications of the details of the associated implementation.

PJM makes two mistakes in its implementation approach to creating a new VRR curve and to the definition of the maximum price.

The first mistake is that PJM does not propose to create a new VRR curve with a consistently defined new Point A, Point B and Point C. Rather, PJM simply uses the existing VRR curve including a maximum price of Gross CONE and draws a horizontal

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and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

4 OATT Attachment DD § 5.10(a)(i).

5 For the 2026/2027 and subsequent delivery years, the corresponding MW quantities are set at 99.0 percent of the reliability requirement for point A, 101.5 percent of the reliability requirement for point B and 104.5 percent of the reliability requirement for point C.

line at the maximum price from the Y axis until it intersects the existing VRR curve. PJM also draws another horizontal line at the minimum price from the Y axis until it intersects the existing VRR curve. This approach is not consistent with defining a new maximum price at $325/MW-day and creating a new, internally consistent VRR curve. (See Figure 1.)

The result of PJM's approach is that Point A on the VRR curve is no longer defined by the maximum price and 99.0 percent of the reliability requirement MW. PJM's equivalent of Point A, the first inflection point on the VRR curve, now occurs at a MW point that is greater than the reliability requirement. PJM's approach increases the MW that will clear at the maximum price compared to the VRR curve definition. In addition, PJM continues to define Point B based on 0.75*Net CONE despite the fact that Net CONE no longer affects Point A. PJM's proposed use of Net CONE results in 10 of 17 LDAs with a Point B that is less than the minimum price.

The second mistake is that PJM does not propose to implement the maximum price of $325 from the Agreement. Rather, PJM proposes to modify the maximum price based on the ELCC value for the reference technology, a dual fuel CT. PJM's approach is that the maximum price of $325/MW-day in UCAP terms equals a maximum price of $256.75/MW-day in ICAP terms, using a dual fuel CT ELCC of .79. PJM proposes to make the ICAP price the defined price and change the UCAP price to match it if the ELCC for the dual fuel CT changes. Under PJM's approach, if the ELCC increases, the maximum price would decrease. Under PJM's approach, if the ELCC decreases, the maximum price would increase.

For example, if the reference resource's ELCC based accredited UCAP factor were reduced from 0.79 to 0.73, the maximum price would increase from $325/MW-day to more than $350/MW-day ($352/MW-day). If the RTO cleared at the $350/MW-day maximum price (Scenario 83), this would result in an increase of $1,240,735,375 in annual capacity market revenues compared to using a $325/MW-day maximum price (Scenario 79).

PJM's proposal is inconsistent with a maximum price of $325/MW-day. The Agreement maximum price is a price in UCAP terms. The maximum price is a fixed value in UCAP terms and should be implemented as a fixed value. PJM's reversed proposal would convert the Agreement price to an ICAP price and make the ICAP price the fixed value. The PJM capacity market price is defined in UCAP terms. The Agreement is defined in UCAP terms. PJM's proposal is that if the ELCC changes the ICAP price calculated at an ELCC of .79 would remain the same and the Agreement UCAP price must change. There is no reason to introduce this calculation, this change in the maximum price or the associated confusion. If the ELCC changes, the Agreement maximum price remains the same and the calculated ICAP price would change. Given the volatility of PJM's ELCC values, PJM's ability to change ELCC results by switching forecasts, and the multiple issues with PJM's calculations of ELCC values, especially for thermal resources like CTs, there is no reason to make the Agreement maximum price a function of the ELCC values. The PJM proposal to make the maximum price in the Agreement a function of the ELCC for dual fuel CTs is inconsistent with creating certainty for market participants.

Conclusions

Applying the maximum price and the minimum price defined by the Agreement is a reasonable starting place for immediate capacity market design reforms that should be made prior to the 2026/2027 BRA. The approach defined by the Agreement is similar to the MMU recommendation to use 1.5 times Net CONE, capped at Gross CONE, as the maximum price or Point A on the VRR curve. The results of applying the Agreement are comparable to the results of applying the MMU recommendation on the maximum price. These conclusions assume that the Agreement is implemented as recommended by the MMU.

The Agreement maximum price of $325/MW-Day is 14 percent higher than the average of 1.5 * Net CONE values for all LDAs.

In addition, the three related MMU recommendations that are not addressed in the Agreement and remain as contested issues at FERC should also be implemented.

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 capped at $325.00 per UCAP MW-day, a 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 $16,092,691,225, an increase of $1,405,643,867, or 9.6 percent, compared to the actual results (Scenario 79).

The Agreement proposal would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented. [6] This calculation compares the results of MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.

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[6] The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

The Agreement proposal would result in market revenues lower than PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,833,732,106 per year if the MMU RMR recommendation were implemented but the two additional MMU recommendations were not implemented. This calculation compares the results of MMU Scenario 56 (from Part E) for the PJM result and Scenario 80 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.

The Agreement is consistent with a competitive market outcome and consistent with the underlying PJM Capacity Market supply and demand fundamentals. PJM's maximum price point of the greater of Gross CONE and 1.75 times Net CONE is not based on economic logic and is not a basis for a competitive market outcome. The maximum price resulting from the Agreement will be higher than the average of all historical capacity market weighted average BRA clearing prices prior to the 2025/2026 Delivery Year, which is $116.30/MW-day.[7] [8]

The MMU continues to oppose the use of a floor price in the PJM capacity markets.

Recommendations

The MMU recommends approval of the Agreement maximum price of $325/MW-day in UCAP terms and minimum price of $175/MW-day in UCAP terms for the 2026/2027 and the 2027/2028 BRAs.

The MMU recommends that the maximum price apply to the MW for Point A as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve. The MW quantity at Point A is set at 99.0 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

The MMU recommends an explicit definition of the price at Point B as .75 times the maximum price that would correspond to the MW for Point B as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve given the maximum

7 See *2024 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, Table 5-19.

8 Some price separated LDAs have had higher prices. In the 2015/2026 BRA, ATSI LDA cleared at $357.00 per MW-day. In the 2024/2025 BRA, DPL South LDA cleared at $426.17 per MW-day as a result of a mistake by PJM. In the 2024/2025 First IA, PSEG North LDA cleared at $410.95 per MW-day. In the 2024/2025 Second IA, PSEG North LDA cleared at $310.00 per MW-day. In the 2024/2025 Third IA, PSEG North LDA cleared at $256.76 per MW-day.

price. The MW quantity at Point B is set at 101.5 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

The MMU recommends that the price at Point C be defined to be the $175/MW-day minimum price from the Agreement that would correspond with the MW for Point C as defined in the PJM tariff for the VRR curve. This maintains the basic logic of the VRR curve given the minimum price. The MW quantity at Point C is set at 104.5 percent of the reliability requirement for the 2026/2027 and subsequent delivery years.

Although not addressed by the Agreement, the MMU continues to make three short term recommendations and one longer term recommendation. The MMU continues to recommend that the must offer rule in the capacity market apply to all capacity resources in the 2026/2027 BRA and subsequent BRAs, without conditions. The MMU continues to recommend that the capacity of the RMR units be included in both the CETO/CETL analysis and in the supply of capacity in all BRAs during which RMR units are designated. The MMU continues to recommend that the ELCC capacity accreditation recognize the winter capability of thermal resources rather than limiting such resources to summer ratings.

In the longer term, ideally by the 2027/2028 BRA, the MMU recommends that the ELCC approach be significantly refined to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter and all hourly risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly unit specific performance rather than based on relatively inflexible class capacity accreditation ratings derived from a small number of hours of poor performance.

Summary

Table 5 through Table 8 show the summary of the revenue impacts of the scenarios analyzed in Part F.

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 all scenarios included in Part F, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA under the assumption that the forecasted peak load would be 5.0 percent higher than that used in the 2025/2026 BRA. The preliminary RTO wide peak load forecast for the 2025/2026 BRA was 153,883.0 MW. PJM revised the 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.[9] The final RTO wide peak load forecast for the 2025/2026 Delivery Year is 154,534.1 MW, 651.1 MW or 0.4 percent higher than the preliminary peak load forecast for the 2025/2026 BRA.[10] The RTO wide preliminary peak load forecast for the 2026/2027 BRA is 158,937 MW, 5,054 MW or 3.3 percent higher than the preliminary peak load forecast for the 2025/2026 BRA.[11] 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 11 transmission zones, but mainly concentrated in the Dominion and AEP Transmission Zones, is the primary reason for the expected higher demand in the immediate future. PJM estimated that the preliminary accepted requests added up to approximately 9,000 MW for 2025 and approximately 12,000 MW for 2026.[12]

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9 See 2025 PJM Long-Term Load Forecast Report <https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf> (January 24, 2025).

10 The forecast peak load values used in RPM auctions includes adjustments for load served outside PJM.

11 The peak load forecast value for the 2026/2027 Delivery Year excludes adjustments for load served outside PJM. The planning parameters for the 2026/2027 BRA including the preliminary peak load forecast adjusted for load served outside PJM will be released no later than March 31, 2025. The final peak load forecast for the 2026/2027 Delivery Year will be released in January 2026. The planning parameters for the 2026/2027 Third IA including the final peak load forecast adjusted for load served outside PJM will be released sometime in January 2026, based on a February 2026 auction opening.

12 See Load Adjustment Requests Summary for 2025 Load Forecast - Preliminary, presented at Planning Committee Meeting <https://www.pjm.com/-/media/committees-

The scenarios compare the results of implementing the Agreement under a 5.0 percent increase in forecast load scenario using the MMU's proposed approach to the results of the 2025/2026 BRA that did not include that increase in load. The result of increasing the load forecast is to increase the demand and to increase total market revenues, holding everything else constant. The scenarios include a range of maximum prices for comparison purposes, but the scenario with a $325/MW-day maximum price reflects the maximum price from the Agreement.

In order to calculate the difference between the results from implementing the Agreement with the results of implementing PJM's filed proposal, scenarios 79, 80, 81 and 82 from Part F need to be compared with scenarios 55, 56, 57 and 58 from Part E. Those Part E scenarios show the revenues that result from implementing PJM's filed proposal including a maximum price equal to the greater of Gross CONE and 1.75 times Net CONE, plus the three MMU recommendations. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA.[13]

The basic conclusion is that, if implemented consistent with the MMU implementation approach, the Agreement would result in market revenues lower than the market revenues that would result from PJM's proposal to use a maximum price of the greater of Gross CONE and 1.75 times Net CONE by $8,731,577,104 per year if the three additional MMU recommendations were not implemented. This calculation compares the results of MMU Scenario 55 (from Part E) for the PJM result and Scenario 79 (from Part F) for the Agreement result. These comparisons all include an increase in forecasted peak load of 5.0 percent over the load used in the 2025/2026 BRA. There are more details in this Part F.

Prices for Point A on VRR Curve

Table 1 shows the price coordinates used for the maximum price, the price at point A of the VRR curves included in the scenarios in Part F. The price coordinates include the Agreement value of $325/MW-day and a range above and below that value. Table 1 also shows the price coordinates for the prices at Point B, corresponding to each Point A.

The current definition of the price at Point B on the VRR curve is .75 times Net CONE. In each scenario defined in Part F, the price at Point B is defined as .75 times the defined

groups/committees/pc/2024/20241203/20241203-item-07----large-load-adjustment-requests-summary.ashx> (December 2, 2024)

13 The results of PJM's filed proposal are the same regardless of whether the VRR curve is based on the higher of Gross CONE and 1.0 times Net CONE (Scenario 55 from Part E), the higher of Gross CONE and 1.5 times Net CONE (Scenario 59 from Part E) or the higher of Gross CONE and 1.75 times Net CONE. The Gross CONE exceeds 1.75 times Net CONE for all price separated LDAs in all these scenarios.

maximum price. This is the most logical interpretation of the price of Point B under the Agreement terms. The maximum price is interpreted as Net CONE given that the Agreement replaces the various CONE values for Point A with a defined price. Point B remains part of the VRR curve unless Point B falls below the minimum price.

Table 2 shows the prices coordinates of the VRR curves for the RTO and each modeled LDA based on PJM's approach that uses the higher of Gross CONE and 1.75 times Net CONE as the maximum price. The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.

Table 3 shows the price coordinates of the VRR curves for the RTO and each modeled LDA under PJM's proposed approach to implementing the Agreement.[14] The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. Under PJM's proposed implementation of the Agreement, the maximum price ($325/MW-day) and minimum price ($175/MW-day) are applied to PJM's original proposed VRR curve. The price coordinate for Point B would be same as the original VRR curve, which is set at 0.75 times Net CONE. Point B falls below the minimum price for 10 of 17 LDAs under PJM's approach.

Table 4 shows the price coordinates of the VRR curves for the RTO and each modeled LDA under the MMU's proposed approach to implementing the Agreement. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. Under the MMU proposed implementation of the Agreement, the maximum price ($325/MW-day) and minimum price ($175/MW-day) are applied and the price coordinate for Point B is equal to the greater of 0.75 times the maximum price and the minimum price.

Figure 1 compares the VRR curves under the PJM proposal and MMU proposal for the RTO. The price coordinates are based on PJM's updates to Gross CONE and Net CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.

Figure 2 compares the VRR curves under the PJM proposal and MMU proposal for the PSEG LDA. The price coordinates are based on PJM's updates to Gross CONE and Net

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14 See Consultation: Capacity Market Demand Curve Adjustments Pursuant to Proposed Settlement, to be presented at Special Members Committee Meeting <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250207-special/item-01a---capacity-market-demand-curve-adjustments-pursuant-to-proposed-settlement.pdf> (February 7, 2025).

CONE values. The MW quantities correspond to 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. For the PSEG LDA, 1.75 times Net CONE is greater than Gross CONE.

The scenarios do not explicitly model the minimum price because the minimum price is not a binding constraint in any scenario.

PJM's updates to Gross CONE and Net CONE values were provided after Part C and Part D.[15] [16] Gross CONE decreased from the original Combustion Turbine (CT) MOPR parameters that PJM posted for the 2026/2027 Base Residual Auction in October 2024 because PJM changed the reference resource for the VRR curve from a gas fired CT with firm gas (single fuel) to a gas fired CT with nonfirm gas and oil backup (dual fuel). PJM also updated the net revenue offset and therefore the Net CONE values using the November fuel and energy forward prices for the delivery year.

Table 1 Price coordinates used for Point A and Point B of the VRR Curve in the scenarios

	Maximum Price ($/UCAP MW-day)	Point B ($/UCAP MW-day)
Scenarios 71,72,73,74	$250.00	$187.50
Scenarios 75,76,77,78	$300.00	$225.00
Scenarios 79,80,81,82	$325.00	$243.75
Scenarios 83,84,85,86	$350.00	$262.50

15 In Part C and Part D, CT Gross CONE are from 2026/2027 Default New Entry MOPR Offer Prices <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-dy-mopr-prices-for-new-entry.ashx> (July 5, 2024). Forward E&AS revenues are provided by PJM.

16 See Attachment D, FERC Docket No. ER25-682-000, Revisions to PJM Capacity Market (December 9, 2024). Forward E&AS revenues are provided by PJM.

Table 2 PJM Filed Proposal: Price coordinates using CT as the reference resource; maximum price set at the higher of Gross CONE and 1.75 times Net CONE; Forward E&AS offset; No maximum and minimum prices

	Point A		Point B		Point C	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$499.32	138,699.1	$149.72	142,485.7	$0.00	149,778.2
MAAC	$497.66	52,755.5	$192.02	54,195.8	$0.00	56,969.6
EMAAC	$552.44	30,612.9	$236.76	31,448.7	$0.00	33,058.2
SWMAAC	$492.46	13,348.7	$109.51	13,713.4	$0.00	14,415.9
PSEG	$620.10	10,546.7	$265.76	10,834.6	$0.00	11,389.2
PS-NORTH	$620.10	5,356.2	$265.76	5,502.5	$0.00	5,784.1
DPL-SOUTH	$471.65	2,720.1	$162.61	2,794.4	$0.00	2,937.4
PEPCO	$492.46	6,485.2	$170.66	6,662.2	$0.00	7,003.2
ATSI	$511.88	12,052.0	$160.46	12,381.0	$0.00	13,014.6
ATSI-CLEVELAND	$511.88	5,008.3	$160.46	5,145.0	$0.00	5,408.4
COMED	$587.13	20,590.6	$251.63	21,152.7	$0.00	22,235.3
BGE	$492.46	6,864.4	$48.35	7,051.8	$0.00	7,412.7
PPL	$527.42	8,669.0	$226.04	8,905.6	$0.00	9,361.4
DAY	$511.88	3,483.1	$126.30	3,578.1	$0.00	3,761.3
DEOK	$511.88	5,500.5	$141.69	5,650.6	$0.00	5,939.9
DOM	$511.88	25,463.0	$72.62	26,158.1	$0.00	27,496.9

Table 3 PJM Agreement Proposal: Price coordinates using CT as the reference resource; Maximum price at $325/MW-day and minimum price at $175/MW-day[17]

	Point A		Point B		Point C		Point D	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$325.00	140,587.2	$175.00	142,211.9	$175.00	+Inf.		
MAAC	$325.00	53,569.2	$192.02	54,195.8	$175.00	54,441.7	$175.00	+Inf.
EMAAC	$325.00	31,215.1	$236.76	31,448.7	$175.00	31,868.5	$175.00	+Inf.
SWMAAC	$325.00	13,508.2	$175.00	13,651.0	$175.00	+Inf.		
PSEG	$325.00	10,786.5	$265.76	10,834.6	$175.00	11,024.0	$175.00	+Inf.
PS-NORTH	$325.00	5,478.0	$265.76	5,502.5	$175.00	5,598.7	$175.00	+Inf.
DPL-SOUTH	$325.00	2,755.4	$175.00	2,791.4	$175.00	+Inf.		
PEPCO	$325.00	6,577.3	$175.00	6,659.8	$175.00	+Inf.		
ATSI	$325.00	12,227.0	$175.00	12,367.4	$175.00	+Inf.		
ATSI-CLEVELAND	$325.00	5,081.0	$175.00	5,139.3	$175.00	+Inf.		
COMED	$325.00	21,029.8	$251.63	21,152.7	$175.00	21,482.4	$175.00	+Inf.
BGE	$325.00	6,935.1	$175.00	6,998.4	$175.00	+Inf.		
PPL	$325.00	8,827.9	$226.04	8,905.6	$175.00	9,008.5	$175.00	+Inf.
DAY	$325.00	3,529.1	$175.00	3,566.1	$175.00	+Inf.		
DEOK	$325.00	5,576.3	$175.00	5,637.1	$175.00	+Inf.		
DOM	$325.00	25,758.7	$175.00	25,996.1	$175.00	+Inf.		

[17] See Consultation: Capacity Market Demand Curve Adjustments Pursuant to Proposed Settlement, to be presented at Special Members Committee Meeting <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250207-special/item-01a---capacity-market-demand-curve-adjustments-pursuant-to-proposed-settlement.pdf> (February 7, 2025).

Table 4 IMM Agreement Proposal: Price coordinates using $325/MW-day as the maximum price and $175/MW-day as the minimum price and 0.75 times maximum Price for Point B

	Point A		Point B		Point C		Point D	
	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW	$/MW-day	MW
RTO	$325.00	138,699.1	$243.75	142,485.7	$175.00	144,542.6	$175.00	+Inf.
MAAC	$325.00	52,755.5	$243.75	54,195.8	$175.00	54,978.2	$175.00	+Inf.
EMAAC	$325.00	30,612.9	$243.75	31,448.7	$175.00	31,902.7	$175.00	+Inf.
SWMAAC	$325.00	13,348.7	$243.75	13,713.4	$175.00	13,911.5	$175.00	+Inf.
PSEG	$325.00	10,546.7	$243.75	10,834.6	$175.00	10,991.0	$175.00	+Inf.
PS-NORTH	$325.00	5,356.2	$243.75	5,502.5	$175.00	5,581.9	$175.00	+Inf.
DPL-SOUTH	$325.00	2,720.1	$243.75	2,794.4	$175.00	2,834.7	$175.00	+Inf.
PEPCO	$325.00	6,485.2	$243.75	6,662.2	$175.00	6,758.4	$175.00	+Inf.
ATSI	$325.00	12,052.0	$243.75	12,381.0	$175.00	12,559.7	$175.00	+Inf.
ATSI-CLEVELAND	$325.00	5,008.3	$243.75	5,145.0	$175.00	5,219.3	$175.00	+Inf.
COMED	$325.00	20,590.6	$243.75	21,152.7	$175.00	21,458.0	$175.00	+Inf.
BGE	$325.00	6,864.4	$243.75	7,051.8	$175.00	7,153.6	$175.00	+Inf.
PPL	$325.00	8,669.0	$243.75	8,905.6	$175.00	9,034.2	$175.00	+Inf.
DAY	$325.00	3,483.1	$243.75	3,578.1	$175.00	3,629.8	$175.00	+Inf.
DEOK	$325.00	5,500.5	$243.75	5,650.6	$175.00	5,732.2	$175.00	+Inf.
DOM	$325.00	25,463.0	$243.75	26,158.1	$175.00	26,535.7	$175.00	+Inf.

Figure 1 Comparison of VRR Curves for RTO

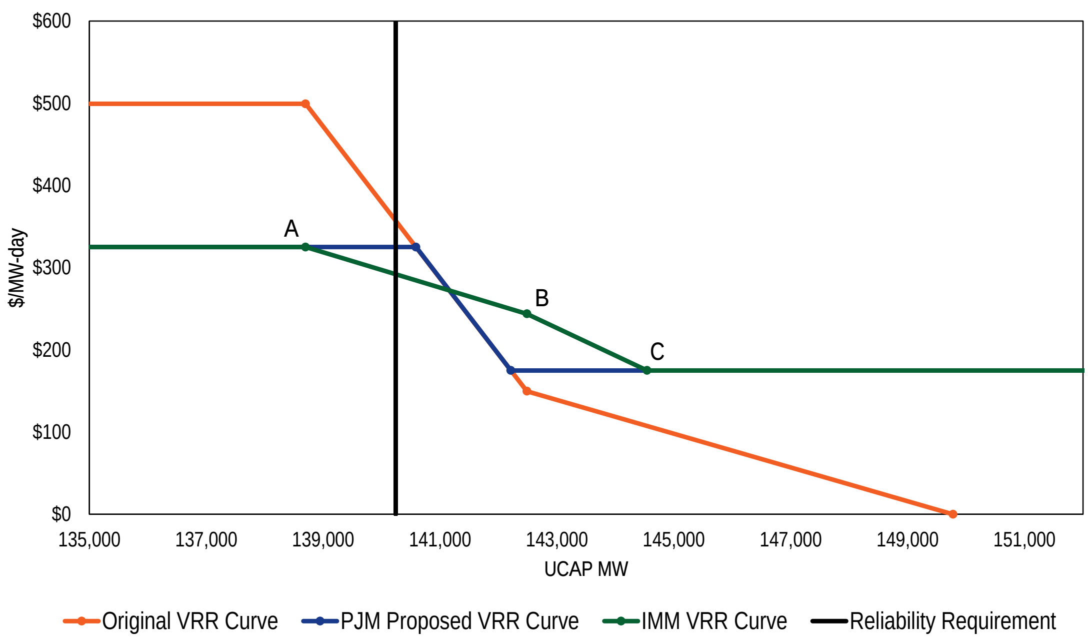
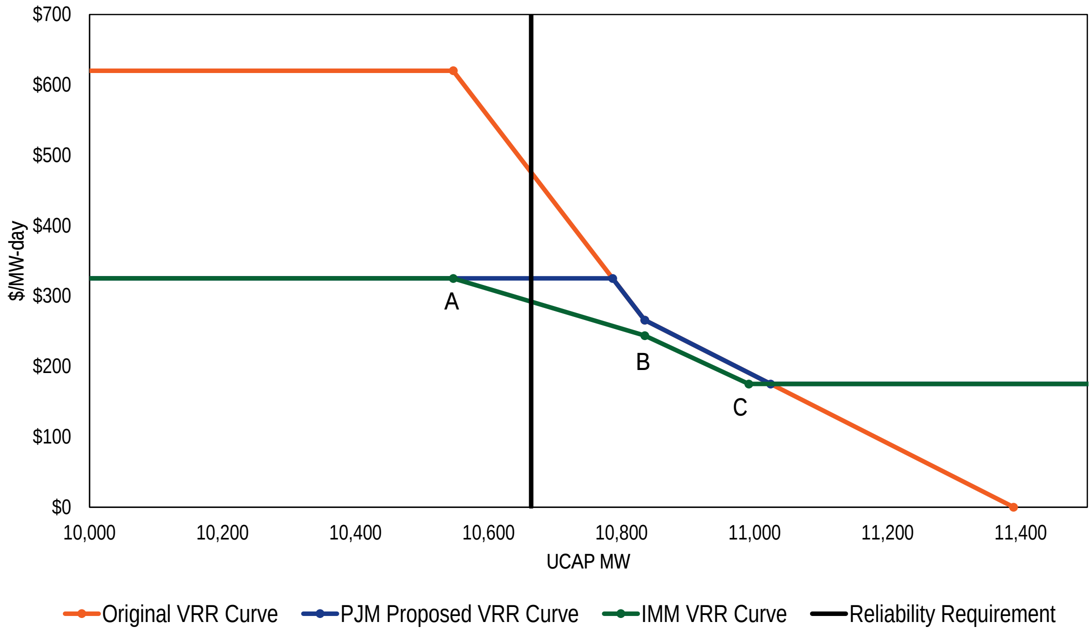


Figure 2 Comparison of VRR Curves for PSEG LDA



Results: $250 per MW-day Cap; 5.0 increase in Forecasted Load

In Scenarios 71, 72, 73 and 74, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $250.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA.[18] The maximum price (point A) is set at $250.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($187.50 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 5 shows the impact on RPM revenues for Scenario 71. 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 capped at $250.00 per UCAP MW-day, a 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 $12,372,204,250, a decrease of $2,314,843,108, or 15.8 percent, compared to the actual results (Scenario 71). From another perspective, the actual 2025/2026 VRR curve resulted in 18.7 percent higher 2025/2026 RPM BRA revenues compared to what RPM revenues

[18] Scenarios 2, 3 and 4 address the impact of the failure to offer by some categorically exempt resources, the impact of excluding RMR supply and the impact of understated winter ratings for thermal resources. These scenarios are included in the analysis in Parts A, B, C, D and E.

would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $250.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 71).

Table 5 shows the impact on RPM revenues for Scenario 72. 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 71, 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 $12,522,702,875, a decrease of $2,164,344,483, or 14.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, 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 17.3 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 72).

Table 5 shows the impact on RPM revenues for Scenario 73. 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 71, 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 had 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 $13,025,563,375, a decrease of $1,661,483,983, or 11.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, 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 12.8 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 73).

Table 5 shows the impact on RPM revenues for Scenario 74. 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 55, 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 had 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 $13,176,536,500, a decrease of $1,510,510,858, or 10.3 percent, compared to the actual results. From another perspective, if in addition to Scenario 71, 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 11.5 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 74).

Table 5 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $250 per MW-day; 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
71	VRR curve based on $250 per UCAP MW-Day Cap	$12,372,204,250	$2,314,843,108	18.7%	(15.8%)
72	Scenario 55 and RMR resources	$12,522,702,875	$2,164,344,483	17.3%	(14.7%)
73	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,025,563,375	$1,661,483,983	12.8%	(11.3%)
74	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$13,176,536,500	$1,510,510,858	11.5%	(10.3%)

Results: $300 per MW-day Cap; 5.0 Increase in Forecasted Load

In Scenarios 75, 76, 77 and 78, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $300.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $300.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($225.00 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 6 shows the impact on RPM revenues for Scenario 71. 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 capped at $300.00 per UCAP MW-day, a 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 $14,853,806,400, an increase of $166,759,042, or 1.1 percent, compared to the actual results (Scenario 75). From another perspective, the actual 2025/2026 VRR curve resulted in 1.1 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $300.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 75).

Table 6 shows the impact on RPM revenues for Scenario 76. 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 75, 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 $15,033,036,000, an increase of $345,988,642, or 2.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, 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 2.3 percent decrease 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 76).

Table 6 shows the impact on RPM revenues for Scenario 77. 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 75, 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 had 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 $15,636,643,800, an increase of $949,596,442, or 6.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, 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 6.1 percent decrease 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 77).

Table 6 shows the impact on RPM revenues for Scenario 78. 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 75, 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 had 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 $15,818,490,450, an increase of $1,131,443,092, or 7.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 75, 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, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 7.2 percent decrease 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 78).

Table 6 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $300 per MW-day; 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
75	VRR curve based on $300 per UCAP MW-Day Cap	$14,853,806,400	($166,759,042)	(1.1%)	1.1%
76	Scenario 59 and RMR resources	$15,033,036,000	($345,988,642)	(2.3%)	2.4%
77	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,636,643,800	($949,596,442)	(6.1%)	6.5%
78	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$15,818,490,450	($1,131,443,092)	(7.2%)	7.7%

Results: $325 per MW-day Cap; 5.0 increase in Forecasted Load

In Scenarios 79, 80, 81 and 82, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $325.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $325.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($243.75 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 7 shows the impact on RPM revenues for Scenario 79. 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 capped at $325.00 per UCAP MW-day, a 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 $16,092,691,225, an increase of $1,405,643,867, or 9.6 percent, compared to the actual results (Scenario 79). From another perspective, the actual 2025/2026 VRR curve resulted in 8.7 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $325.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 79).

Table 7 shows the impact on RPM revenues for Scenario 80. 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 79, 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 $16,288,244,538, an increase of $1,601,197,180, or 10.9 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, 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 9.8 percent decrease 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 80).

Table 7 shows the impact on RPM revenues for Scenario 81. 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 79, 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 had 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 $16,941,963,188, an increase of $2,254,915,830, or 15.4 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, 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 13.3 percent decrease 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 81).

Table 7 shows the impact on RPM revenues for Scenario 82. 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 79, 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 $17,138,323,150, an increase of $2,451,275,792, or 16.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 79, 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 14.3 percent decrease 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 82).

Table 7 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $325 per MW-day; 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
79	VRR curve based on $325 per UCAP MW-Day Cap	$16,092,691,225	($1,405,643,867)	(8.7%)	9.6%
80	Scenario 79 and RMR resources	$16,288,244,538	($1,601,197,180)	(9.8%)	10.9%
81	Scenario 79 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$16,941,963,188	($2,254,915,830)	(13.3%)	15.4%
82	Scenario 79 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$17,138,323,150	($2,451,275,792)	(14.3%)	16.7%

Results: $350 per MW-day Cap; 5.0 Increase in Forecasted Load

In Scenarios 83, 84, 85 and 86, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $350.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $350.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($262.50 per UCAP MW-day). The corresponding MW quantities are the same as Scenario 8 analyzed in Part C.

Table 8 shows the impact on RPM revenues for Scenario 83. 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 capped at $350.00 per UCAP MW-day, a 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 $17,333,426,600, an increase of $2,646,379,242, or 18.0 percent, compared to the actual results (Scenario 83). From another perspective, the actual 2025/2026 VRR curve resulted in 15.3 percent lower 2025/2026 RPM BRA revenues compared to what RPM revenues would have been had PJM cleared the auction using a VRR curve with maximum price (point A) set at $325.00 per UCAP MW-day, and 5.0 percent higher forecasted peak load (Scenario 83).

Table 8 shows the impact on RPM revenues for Scenario 84. 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 83, 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 $17,544,022,475, an increase of $2,856,975,117, or 19.5 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, 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 16.3 percent decrease 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 84).

Table 8 shows the impact on RPM revenues for Scenario 85. 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 83, 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 had 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 $18,248,027,175, an increase of $3,560,979,817, or 24.2 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, 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 19.5 percent decrease 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 85).

Table 8 shows the impact on RPM revenues for Scenario 86. 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 83, 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 had 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 $18,459,491,750, an increase of $3,772,444,392, or 25.7 percent, compared to the actual results. From another perspective, if in addition to Scenario 83, 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, the MW categorically exempt from the RPM must offer requirement that did not offer had been offered, resulted in a 20.4 percent decrease 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 86).

Table 8 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $350 per MW-day; 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
83	VRR curve based on $350 per UCAP MW-Day Cap	$17,333,426,600	($2,646,379,242)	(15.3%)	18.0%
84	Scenario 67 and RMR resources	$17,544,022,475	($2,856,975,117)	(16.3%)	19.5%
85	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$18,248,027,175	($3,560,979,817)	(19.5%)	24.2%
86	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	$18,459,491,750	($3,772,444,392)	(20.4%)	25.7%

Results: Cleared UCAP MW

Table 9 through Table 12 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 9 shows the impact on the cleared UCAP MW for the auction for Scenarios 71 through 74. In Scenarios 71, 72, 73 and 74, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $250.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $250.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($187.50 per UCAP MW-day).

Table 10 shows the impact on the cleared UCAP MW for the auction for Scenarios 75 through 78. In Scenarios 75, 76, 77 and 78, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $300.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $300.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($225.00 per UCAP MW-day).

Table 11 shows the impact on the cleared UCAP MW for the auction for Scenarios 79 through 82. In Scenarios 79, 80, 81 and 82, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $325.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $325.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($243.75 per UCAP MW-day).

Table 12 shows the impact on the cleared UCAP MW for the auction for Scenarios 83 through 86. In Scenarios 83, 84, 85 and 86, the MMU analyzed the impact on the actual auction results for the 2025/2026 BRA of using a VRR curve capped at $350.00 per UCAP MW-day, in combination with scenarios 2, 3 and 4 from Part A and a 5.0 percent higher forecasted peak load than used in the 2025/2026 BRA. The maximum price (point A) is set at $350.00 per UCAP MW-day. The price for point B is set at the 0.75 times the maximum price ($262.50 per UCAP MW-day).

Table 9 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $250 per MW-day; 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
71	VRR curve based on $250 per UCAP MW-Day Cap	135,585.8	98.2	0.1%	(0.1%)
72	Scenario 55 and RMR resources	137,235.1	(1,551.1)	(1.1%)	1.1%
73	Scenario 55 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,745.9	(7,061.9)	(4.9%)	5.2%
74	Scenario 55 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,400.4	(8,716.4)	(6.0%)	6.4%

Table 10 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $300 per MW-day; 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
75	VRR curve based on $300 per UCAP MW-Day Cap	135,651.2	32.8	0.0%	(0.0%)
76	Scenario 59 and RMR resources	137,288.0	(1,604.0)	(1.2%)	1.2%
77	Scenario 59 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,800.4	(7,116.4)	(5.0%)	5.2%
78	Scenario 59 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,461.1	(8,777.1)	(6.1%)	6.5%

Table 11 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve Capped at $325 per MW-day; 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
79	VRR curve based on $325 per UCAP MW-Day Cap	135,660.2	23.8	0.0%	(0.0%)
80	Scenario 79 and RMR resources	137,308.7	(1,624.7)	(1.2%)	1.2%
81	Scenario 79 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,819.5	(7,135.5)	(5.0%)	5.3%
82	Scenario 79 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,474.8	(8,790.8)	(6.1%)	6.5%

Table 12 Scenario summary for 2025/2026 RPM Base Residual Auction: VRR Curve capped at $350 per MW-day; 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
83	VRR curve based on $350 per UCAP MW-Day Cap	135,682.4	1.6	0.0%	(0.0%)
84	Scenario 67 and RMR resources	137,330.9	(1,646.9)	(1.2%)	1.2%
85	Scenario 67 and Winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	142,841.7	(7,157.7)	(5.0%)	5.3%
86	Scenario 67 and all categorically exempt offers, winter ratings and IRM at 17.8 percent (same as BRA) and RMR resources	144,497.0	(8,813.0)	(6.1%)	6.5%

Table 13 shows the clearing prices for the scenarios analyzed in Part F. There was no price separation between LDAs in any of the scenarios analyzed. All LDAs in every scenario analyzed cleared at the maximum price on the VRR curve. The clearing price was set by the maximum price in every scenario analyzed.

Table 13 Clearing Prices by Scenario

	Clearing Price (All LDAs) ($/UCAP MW-day)
Scenarios 71,72,73,74	$250.00
Scenarios 75,76,77,78	$300.00
Scenarios 79,80,81,82	$325.00
Scenarios 83,84,85,86	$350.00