Monitoring Analytics

Analysis of the 2019/2020 RPM Base Residual Auction

The Independent Market Monitor for PJM

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Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the thirteenth Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2019/2020 Delivery Year) which was held from May 11 to 17, 2016, and responds to questions raised by PJM members and market observers about that auction. The MMU prepares a report for each RPM Auction.

This report addresses, explains and quantifies the basic market outcomes. This report also addresses and quantifies the impact on market outcomes of: the Variable Resource Requirement (VRR) Curve shape; the ComEd Capacity Emergency Transfer Limit (CETL); the forecast peak load; the net revenue offset calculation; Demand Resources (DR); the definition of capacity products; capacity imports; and the EE add back mechanism.

Conclusions and Recommendations

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

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

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

The definition of a competitive offer was changed in the Capacity Performance rules now part of the PJM Capacity Market rules. For units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their CP bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio and expected PAH, the competitive, profit maximizing offer is (net CONE * B), where B is the expected average balancing ratio. This is the default offer cap for such units.[1]

The MMU verified the reasonableness of cost data and calculated the derived offer caps based on submitted data; calculated unit net revenues; verified that CP offer caps for low ACR units did not exceed net CONE times B; reviewed Minimum Offer Price Rule (MOPR) exception and exemption requests; reviewed offers for Planned Generation Capacity Resources; verified capacity exports; verified offers based on opportunity costs; reviewed requests for exceptions to the RPM must offer requirement; reviewed requests for exceptions to the Capacity Performance (CP) must offer requirement; verified the sell offer Equivalent Demand Forced Outage Rates (EFORds); reviewed requests for alternate maximum EFORds; reviewed documentation for Intermittent Resources and Capacity Storage Resources to support CP eligibility; reviewed risk adders; verified clearing prices based on the demand (VRR) curves and the Base Capacity Constraints and the Base Capacity Demand Resource Constraints; and verified that the market

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

structure tests were applied correctly.[2] All participants to whom the three pivotal supplier (TPS) test was applied (in the RTO, EMAAC, ComEd, and BGE RPM markets) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[3] [4] The offer caps are designed to reflect the marginal cost of capacity. Based on the data and this review, the MMU concludes that the results of the 2019/2020 RPM Base Residual Auction were competitive, with the caveat that although the Capacity Performance design addressed the most significant issues with the capacity market design, the Capacity Performance design was not fully implemented in the 2019/2020 BRA and there continue to be issues with the capacity market design which have significant consequences for market outcomes.

The Capacity Performance design addressed significant recommendations raised by the MMU in prior reports. These recommendations were included in the Capacity Performance design which will not be fully implemented until the 2020/2021 Delivery Year. The issues addressed by the MMU's prior recommendations continue to be issues in the Base Capacity auction. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the Capacity Market design be strengthened. The MMU had recommended that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the Capacity Market as generation resources. The MMU had recommended that both the Limited and the Extended Summer DR products be

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

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

4 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).

eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources.

The 2.5 percent offset was implemented to permit DR to clear in Incremental Auctions. The 2.5 percent of demand was withheld in the BRA, and PJM attempted to procure that amount in the IAs for the relevant delivery year, net of any change in the forecast peak load. It was not added to counter persistent forecast errors. Forecast errors should be addressed directly and explicitly for all PJM forecasts. It is essential that PJM use the same forecasts for capacity markets and for transmission planning to ensure the long term consistency of RTEP and RPM. To effectively use a lower forecast for capacity in RPM by reducing demand by an arbitrary 2.5 percent would result in biasing the overall market results in favor of transmission rather than generation solutions to reliability issues. PJM's approach to the forecast issue in the 2019/2020 BRA is a step forward but PJM must continue to improve the sophistication of its forecast methods.

The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible.

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

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

PJM is required to model pseudo ties in its network model in order to perform NERC required real-time operations assessments on a continuous basis. Units located physically and electrically distant from PJM would increase the number of real-time telemetry links required to monitor the pseudo tie with an associated increase in potential telemetry link failures and/or corrupted data.

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

Currently, in the RPM framework, all pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO as opposed to any of the individual locational deliverability areas (LDAs). The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to LDAs illustrates a fundamental issue with capacity imports; capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA. The IMM recommends that the electrical proximity of pseudo tied resources be explicitly accounted for when defining how external resources should be treated when evaluating performance during Performance Assessment Hours in specific LDAs or smaller areas for which a Performance Assessment Hour is declared.

The MMU recommends using the lower of the cost or price-based offer in the calculation of net revenues. This recommendation was rejected by FERC.[5] The FERC approved approach, used in the 2019/2020 BRA, is to use the cost-based offer to calculate energy costs. [6] [7] The FERC approach meant that when the price-based offer was less than the cost-based offer, net revenues would be lower under the FERC approach than under the MMU approach. Therefore the FERC approach meant that offers that incorporated net revenues would be greater than or equal to the offers calculated under the MMU approach. In fact, the FERC approach resulted in an increase of $43,445,014, or 0.6 percent, in the cost of capacity in the 2019/2020 BRA.

The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[8] [9] All DR should be on

5 See 155 FERC ¶ 61,281 (2016).

6 Net revenue values for the 2019/2020 RPM BRA were calculated consistent with the FERC order effective at the time. *See FirstEnergy Solutions Corp. v. PJM Interconnection, L.L.C.*, 148 FERC ¶ 61,140 (2014).

7 The net revenue calculation was revised again effective March 1, 2016. *See Order on Section 206 Investigation*, 154 FERC ¶ 61,151 (2016). As the tariff specified deadlines for offer cap and net revenue calculations for the 2019/2020 RPM Base Residual Auction were completed prior to March 1, 2016, the revised net revenue calculation specified in 154 FERC ¶ 61,151 was not used in the offer cap calculations for the 2019/2020 RPM Base Residual Auction.

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

the demand side of the market rather than on the supply side. The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[10] [11] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[12] The MMU recommends that the MOPR rule be extended to existing units in a manner comparable to the application of the MOPR rule to new units.[13]

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9 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

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

11 See the *2015 State of the Market Report for PJM*, Volume II, Section 5, Capacity.

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

13 See Comments of the Independent Market Monitor for PJM. Docket No. EL16-49-000. (April 11, 2016).

The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. When the mitigation rule changes for DR and EE resources became effective on November 1, 2009, with the result that DR and EE resources were no longer subject to market power mitigation, the RPM market structure and parameters were different than they are under the current rules. In 2009, there was one product defined for capacity, and there were no resource constraints defined. Particularly in LDAs with few suppliers, there is now the potential for DR and EE providers to exercise market power and affect the clearing price.

The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve.[14] The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the RPM Auction optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability.

The MMU recommends that Energy Efficiency Resources not be included on the supply side of the capacity market, because PJM's load forecasts now account for future Energy Efficiency Resources, unlike the situation when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

Results

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the auction. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve equal to the reliability requirement. As shown in Table 12, the 165,814.4 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 22.9 percent and a net excess of 8,722.0 MW over the reliability requirement of 157,092.4 MW.[15] [16] Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side results in a

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

15 The 22.9 percent reserve margin does not include EE on the supply side or the EE add back on the demand side. This is how PJM calculates the reserve margin.

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

calculated reserve margin of 22.6 percent and a net excess of 8,345.7 MW over the reliability requirement of 157,092.4 MW.

The 2019/2020 RPM Base Residual Auction was the second BRA held using the revised shape of the VRR curve. The revised shape of the VRR curve in the 2019/2020 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no change to VRR curve shape in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,584,436,158, a decrease of $415,456,950, or 5.9 percent, compared to the actual results. From another perspective, the use of the revised shape of the VRR curve resulted in a 6.3 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the prior VRR curve shape. (Scenario 1.) Table 1 and Table 2summarize the sensitivity analyses.

The combined change in the ComEd CETL of -1,860.0 MW, or 26.5 percent, from the 2017/2018 level to the 2019/2020 level had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the 2017/2018 CETL value for ComEd had been used in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,612,836,020, a decrease of $387,057,088, or 5.5 percent, compared to the actual results. From another perspective, the use of the 2019/2020 CETL value for ComEd resulted in a 5.9 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the 2017/2018 CETL value for ComEd. (Scenario 2.)

The change in the peak load forecast had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the forecast peak load had not been reduced by 2.6 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $8,101,386,204, an increase of $1,101,493,096, or 15.7 percent, compared to the actual results. From another perspective, the 2.6 percent reduction in the forecast peak load resulted in a 13.6 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction. (Scenario 3.)

The net revenue offset calculation had a smaller but significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the lower of the price-based or cost-based energy offer were used in the net revenue offset calculation for the purpose of calculating RPM offer caps in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,956,448,094, a decrease of $43,445,014, or 0.6 percent, compared to the actual results. From another perspective, using cost-based energy offers in the net revenue offset calculation for the purpose of calculating RPM offer caps resulted in a 0.6 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the lower of the price-based or cost-based energy offer in the net revenue offset calculation. (Scenario 4.)

The inclusion of sell offers for Demand Resources and Energy Efficiency resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for DR or EE, either Base Capacity or CP, in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $9,099,465,731, an increase of $2,099,572,623, or 30.0 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 23.1 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources. (Scenario 5.)

The 2019/2020 RPM Base Residual Auction was the first BRA held using the EE add back mechanism. RPM rules allow Energy Efficiency Resources to participate on the supply side. An adjustment is made to the demand curve through the EE add back mechanism to avoid double counting, since, beginning with the 2019/2020 BRA, EE for the delivery year is reflected in the revised load forecast model for the same delivery year. The EE add back mechanism had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for EE and the EE add back MW were set to zero in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,905,618,435, a decrease of $94,274,673, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resource offers and the EE add back MW, resulted in a 1.4 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if energy efficiency projects were reflected in the demand and EE Resources did not participate on the supply side. (Scenario 6.)

Under the new EE add back MW rules, the demand curve was shifted by an amount greater than the quantity of cleared EE that shifted supply, so the clearing price was increased as a result of the implementation of the EE add back mechanism. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW, and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,983,867,441, a decrease of $16,025,667, or 0.2 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW, resulted in a 0.2 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA. (Scenario 7.)

While the Extended Summer and Limited DR products were eliminated for the 2018/2019 and subsequent Delivery Years, the limited availability Base Capacity DR/EE product had a significant impact in the 2019/2020 BRA.

The inclusion of sell offers for Base Capacity DR and Base Capacity EE had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for Base Capacity DR or Base Capacity EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $8,206,198,971, an increase of $1,206,305,862, or 17.2 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Demand Resources and Base Capacity Energy Efficiency resources resulted in a 14.7 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Demand Resources or Base Capacity Energy Efficiency resources. (Scenario 8.)

The inclusion of sell offers for Capacity Performance DR and Capacity Performance EE had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for CP DR or CP EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,861,332,713, a decrease of $138,560,395, or 2.0 percent, compared to the actual results. From another perspective, the inclusion of Capacity Performance Demand Resources and Capacity Performance Energy Efficiency resources resulted in a 2.0 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Capacity Performance Demand Resources or Capacity Performance Energy Efficiency resources. (Scenario 9.)

Another measure of the impact of sell offers for Capacity Performance DR and Capacity Performance EE is to compare the market results with only generation (Scenario 5) to the market results with only generation, Capacity Performance DR, and Capacity Performance EE (Scenario 8). This identifies the separate impact of Capacity Performance DR and Capacity Performance EE. If only generation, Capacity Performance DR, and Capacity Performance EE had been offered and there had been no offers for Base Capacity DR/EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $8,206,198,971. If only generation had been offered and there had been no offers for DR or EE in the 2019/2020 RPM Base Residual Auction, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $9,099,465,731, an increase of $893,266,760, or 10.9 percent, compared to the results with only generation, Capacity Performance DR, and Capacity Performance EE. From another perspective, the inclusion of sell offers for Capacity Performance DR and Capacity Performance EE resulted in a 9.8 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to the revenues without any Capacity Performance or Base Capacity demand side products.

This is the best measure of the competitive impact of demand side products on the RPM market. The Capacity Performance DR product definition is the only one relatively close to consistent with being a capacity resource although the demand side product should be on the demand side rather than the supply side. Assuming that the DR offers meet appropriate measurement and verification standards and that the DR offers were made with the intention of providing physical resources, competition from the Capacity Performance DR product and Energy Efficiency resources resulted in a 9.8 percent reduction in payments for capacity. This demonstrates that, with these strong assumptions, Capacity Performance DR together with Capacity Performance Energy Efficiency resources had a significant impact on market outcomes and resulted in the displacement of generation resources. Thus, even when the DR product is limited to the Capacity Performance DR product, DR has a significant and appropriate competitive impact on capacity market outcomes, with the stated assumptions. The market design should be modified such that the demand side product is on the demand side rather than the supply side. If the current DR resources are legitimate, there is no reason to believe that the market impact of the demand side product would be significantly different if the demand side product were on the demand side of the market as it should be.

The level of DR products that buy out of their positions after the BRA suggests that the impact of DR on generation investment incentives needs to be carefully considered and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[17] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other capacity resources available in Incremental Auctions. This would suppress the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules governing the BRA.

The inclusion of capacity imports in the 2019/2020 RPM Base Residual Auction had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $7,089,724,034, an increase of $89,830,926, or 1.3 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 1.3 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation resources had been reduced by 25 percent. (Scenario 10.) If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $7,399,063,952, an increase of $399,170,844, or 5.7 percent, compared to the actual results. From another perspective, the impact of including all offers for external generation resources resulted in a 5.4 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation resources had been reduced by 75 percent. (Scenario 12)

The inclusion of sell offers for Base Capacity Resources and Base Capacity DR/EE Resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for Base Capacity Resources and Base Capacity DR/EE Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $12,248,291,567, an increase of $5,248,398,459, or 75.0 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Resources and Base

17 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013" <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

Capacity DR/EE Resources resulted in a 42.9 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Resources and Base Capacity DR/EE Resources. (Scenario 13.)

The combined inclusion of sell offers for CP DR, CP EE, and all Base Capacity Resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for DR, EE, or Base Capacity Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $13,595,336,649, an increase of $6,595,443,541, or 94.2 percent, compared to the actual results. From another perspective, the inclusion of DR, EE, and Base Capacity Resources resulted in a 48.5 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any DR, EE, and Base Capacity Resources. (Scenario 14.)

The inclusion of sell offers for DR, EE, Base Capacity Resources, and external generation resources had a significant impact on the auction results. Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for DR, EE, or Base Capacity Resources and import offers for external generation resources had been reduced by 50 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $14,599,974,126, an increase of $7,600,081,018, or 108.6 percent, compared to the actual results. From another perspective, the inclusion of DR, EE, and Base Capacity Resources and 50 percent of the offers for external generation resources resulted in a 52.1 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any DR, EE, and Base Capacity Resources and 50 percent of import offers for external generation resources. (Scenario 15.)

Tables for Results Section

Table 1 Scenario summary of RPM revenue: 2019/2020 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	RPM Revenue ($ per Delivery Year)	RPM Revenue ($ per Delivery Year)	Percent
0	Actual Results	$6,999,893,108	NA	NA
1	Revised Shape of the VRR Curve	$6,584,436,158	$415,456,950	6.3%
2	ComEd CETL at 2017/2108 Level	$6,612,836,020	$387,057,088	5.9%
3	Forecast Peak Load Reduced by 2.6 Percent	$8,101,386,204	($1,101,493,096)	(13.6%)
4	Net Revenue Offset Calculation	$6,956,448,094	$43,445,014	0.6%
5	Inclusion of DR/EE Offers	$9,099,465,731	($2,099,572,623)	(23.1%)
6	Inclusion of EE Offers and EE Add Back	$6,905,618,435	$94,274,673	1.4%
7	EE Cleared MW Equal to EE Add Back MW	$6,983,867,441	$16,025,667	0.2%
8	Inclusion of Base Capacity DR/EE Offers	$8,206,198,971	($1,206,305,862)	(14.7%)
9	Inclusion of CP DR/EE Offers	$6,861,332,713	$138,560,395	2.0%
10	Inclusion of 75 Percent of Offers for External Generation	$7,089,724,034	($89,830,926)	(1.3%)
11	Inclusion of 50 Percent of Offers for External Generation	$7,280,090,853	($280,197,745)	(3.8%)
12	Inclusion of 25 Percent of Offers for External Generation	$7,399,063,952	($399,170,844)	(5.4%)
13	Inclusion of Base Capacity and Base Capacity DR/EE Offers	$12,248,291,567	($5,248,398,459)	(42.9%)
14	Inclusion of Base Capacity and Base Capacity DR/EE Offers, and CP DR/EE Offers	$13,595,336,649	($6,595,443,541)	(48.5%)
15	Inclusion of Base Capacity and Base Capacity DR/EE Offers, CP DR/EE Offers, and 50 Percent of Offers for External Generation	$14,599,974,126	($7,600,081,018)	(52.1%)

Table 2 Scenario summary of cleared UCAP: 2019/2020 RPM Base Residual Auction

			Scenario Impact	
Scenario	Scenario Description	Cleared UCAP (MW)	Cleared UCAP (MW)	Percent
0	Actual Results	167,305.9	NA	NA
1	Revised Shape of the VRR Curve	164,937.1	2,368.8	1.4%
2	ComEd CETL at 2017/2108 Level	167,164.4	141.5	0.1%
3	Forecast Peak Load Reduced by 2.6 Percent	171,757.1	(4,451.2)	(2.6%)
4	Net Revenue Offset Calculation	167,314.9	(9.0)	0.0%
5	Inclusion of DR/EE Offers	164,225.7	3,080.2	1.9%
6	Inclusion of EE Offers and EE Add Back	165,415.0	1,890.9	1.1%
7	EE Cleared MW Equal to EE Add Back MW	166,902.3	403.6	0.2%
8	Inclusion of Base Capacity DR/EE Offers	165,666.6	1,639.3	1.0%
9	Inclusion of CP DR/EE Offers	166,346.2	959.7	0.6%
10	Inclusion of 75 Percent of Offers for External Generation	167,227.9	78.0	0.0%
11	Inclusion of 50 Percent of Offers for External Generation	167,055.4	250.5	0.1%
12	Inclusion of 25 Percent of Offers for External Generation	166,951.4	354.5	0.2%
13	Inclusion of Base Capacity and Base Capacity DR/EE Offers	164,129.2	3,176.7	1.9%
14	Inclusion of Base Capacity and Base Capacity DR/EE Offers, and CP DR/EE Offers	162,446.2	4,859.7	3.0%
15	Inclusion of Base Capacity and Base Capacity DR/EE Offers, CP DR/EE Offers, and 50 Percent of Offers for External Generation	161,511.0	5,794.9	3.6%

Clearing Prices

Table 3 shows the clearing prices for Capacity Performance Resources in the 2019/2020 BRA by Zone compared to the corresponding net Cost of New Entry (CONE) times (B), where B is the average of the Balancing Ratios during the Performance Assessment

Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year. The clearing prices for CP Resources were less than net CONE times B for every Zone. The ratio of clearing price to net CONE times B was less than 55 percent for 12 of the 20 Zones and exceeded 80 percent for only two Zones.

Table 3 Clearing prices and net CONE times B: 2019/2020 RPM Base Residual Auction

Zone	CP Weighted Average Clearing Price ($ per MW-day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	CP Clearing Price less Net CONE Times B ($ per MW-day)	CP Clearing Price to Net CONE Times B
AECO	$119.77	$279.78	0.81	$226.62	($106.85)	52.9%
AEP	$100.00	$265.54	0.81	$215.09	($115.09)	46.5%
AP	$100.00	$233.48	0.81	$189.12	($89.12)	52.9%
ATSI	$100.00	$246.63	0.81	$199.77	($99.77)	50.1%
BGE	$100.17	$201.39	0.81	$163.13	($62.96)	61.4%
ComEd	$202.77	$306.77	0.81	$248.48	($45.71)	81.6%
DAY	$100.00	$259.04	0.81	$209.82	($109.82)	47.7%
DEOK	$100.00	$268.46	0.81	$217.45	($117.45)	46.0%
DLCO	$100.00	$267.69	0.81	$216.83	($116.83)	46.1%
DPL	$119.77	$244.96	0.81	$198.42	($78.65)	60.4%
Dominion	$100.00	$278.41	0.81	$225.51	($125.51)	44.3%
EKPC	$100.00	$253.57	0.81	$205.39	($105.39)	48.7%
External	$100.00	$279.55	0.81	$226.44	($126.44)	44.2%
JCPL	$119.77	$245.02	0.81	$198.47	($78.70)	60.3%
Met-Ed	$100.00	$260.08	0.81	$210.66	($110.66)	47.5%
PECO	$119.77	$259.36	0.81	$210.08	($90.31)	57.0%
PENELEC	$100.00	$153.58	0.81	$124.40	($24.40)	80.4%
PPL	$100.00	$259.41	0.81	$210.12	($110.12)	47.6%
PSEG	$119.77	$283.28	0.81	$229.46	($109.69)	52.2%
Pepco	$100.00	$228.11	0.81	$184.77	($84.77)	54.1%
RECO	$119.77	$277.06	0.81	$224.42	($104.65)	53.4%

Market Changes

RPM Market Design Changes

Energy Efficiency Resource Rules

Prior to the 2019/2020 Base Residual Auction, EE resources were incorporated on the supply side of the capacity market for four years, after which they were included in the PJM demand forecast and eliminated from the supply side in order to avoid double counting. The 2019/2020 Base Residual Auction was the first BRA for which EE was reflected in the revised load forecast model without a lag.[18] While it would have been logical to eliminate EE from the supply side as a result, an administrative add back mechanism was implemented instead. Effective December 17, 2015, an EE add back

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

mechanism and related changes were implemented to accommodate EE Resource participation on the supply side.[19]

The mechanics of the EE add back mechanism are complex and do not appropriately adjust for the level of cleared EE resources. For each BRA, the reliability requirement of the RTO and each LDA is increased by the UCAP value of all EE Resources with accepted Measurement and Verification Plans for the auction. This increase is the EE add back amount. For the 2019/2020 BRA, this meant that the RTO VRR curve was shifted to the right by 1,891.4 MW. If the initial results of the BRA solution yield a ratio of EE add back MW to cleared EE MW which exceeds a predetermined threshold ratio, the EE add back MW are set equal to the cleared EE MW from the initial solution times the threshold ratio, and the auction clearing is rerun a second and final time. The threshold ratio is equal to the historic three year average of cleared EE MW in all auctions for a given delivery year divided by the cleared EE MW in the BRA for that delivery year. For the 2019/2020 BRA, the ratio in the initial solution of 1,891.4/1,515.1=1.248366444 did not exceed the applicable threshold ratio of 1.380913275. The logic of the threshold is not clear and is not consistent with an appropriate clearing of the Base Residual Auction.

Capacity Performance

Capacity Products and Resource Constraints

Effective for the 2018/2019 and subsequent Delivery Years, the Extended Summer and Limited DR products are eliminated. For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint, are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the inferior products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[20]

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

20 See PJM. “Manual 18: PJM Capacity Market,” Revision 32 (April 1, 2016), p. 7.

Short-Term Resource Procurement Target

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

CP Must Offer Requirement

Effective for the 2018/2019 and subsequent Delivery Years, all Generation Capacity Resources are subject to the CP must offer requirement, with the exception of Intermittent Resources and Capacity Storage Resources which are categorically exempt from the CP must offer requirement. Capacity Storage Resources include hydroelectric, flywheel and battery storage. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. Exceptions to the CP must offer requirement may be requested by demonstrating that the Generation Capacity Resource is physically incapable of satisfying the requirements of a CP Resource. In addition, PJM, considering advice and recommendation from the MMU, may reject eligibility of a resource to offer as CP.[21]

Offer Caps

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

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

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

Coupled Offers

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

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

UCAP Value of DR and EE

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

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

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

External Generation Resources

The 2019/2020 RPM Base Residual Auction was the third BRA conducted under the Capacity Import Limit related rules. Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant Delivery Year due to the curtailment of firm transmission by third parties.[22] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant Delivery Year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

22 147 FERC ¶ 61,060 (2014).

To offer as a CP Resource, an external generation resource must obtain an exception to the CIL. One of the most important requirements for offering a CP capacity import is that it must be pseudo tied. This is a new requirement and consistent with an MMU recommendation. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible.

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

RPM Must Offer Requirement and Market Power Mitigation

The 2019/2020 RPM Base Residual Auction was the sixth BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.[23] These changes included clarifying the applicability of the must-offer requirement and the circumstances under which exemptions from the RPM must-offer requirement would be allowed, revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and mitigation, treating a proposed increase in the capability of a Generation Capacity Resource in exactly the same way as a Planned Generation Capacity Resource for purposes of market power mitigation.

The 2019/2020 RPM Base Residual Auction was the fourth BRA conducted under the process related PJM Tariff revisions.[24] These revisions included defining additional deadlines and accelerating deadlines in advance of an auction related to exception processes for market seller offer caps, alternate maximum EFORds, MOPR, and the RPM must offer requirement.

Effective October 15, 2013, new and revised deadlines for requesting an exception to the RPM must offer requirement due to planned retirement were implemented.[25] The rationale for the earlier deadline is to allow new entrants adequate time to respond and enter the PJM generation interconnection queue in response to a planned retirement. Previously, the deadline for requesting an exception to the RPM must offer requirement based on the reason of retirement was 120 days prior to the auction. For the 2017/2018

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23 134 FERC ¶ 61,065 (2011).

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

25 145 FERC ¶ 61,035 (2013).

BRA, a transition mechanism applied under which the deadline for requesting an exception to the RPM must offer requirement due to planned retirement was November 1, 2013. For all Base Residual Auctions for Delivery Years subsequent to 2017/2018, the deadline is September 1 prior to the auction. For the 2019/2020 BRA, a waiver to the deadline was granted, setting the deadline at October 1, 2015, because Capacity Market Sellers would need information on the results of the CP Transition Incremental Auctions posted on August 31, 2015, and September 9, 2015, in order to make an informed decision on retiring a resource.[26]

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

MOPR

There have been two changes to the RPM Minimum Offer Price Rule (MOPR) effective for recent auctions.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[27] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants, increasing the threshold value used in the screen to 90 percent for CC and CT plants, eliminating the net short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation.

The 2019/2020 RPM Base Residual Auction was the sixth BRA conducted under the revised MOPR and the third conducted under the subsequent FERC orders related to the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[28]

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[26] 152 FERC ¶ 61,151 (2015).

[27] 135 FERC ¶ 61,022 (2011).

[28] 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011), *order on compliance*, 139 FERC ¶ 61,011, *order on compliance*, 140 FERC ¶ 61,123.

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again as a result of a settlement among some parties that was approved by FERC.[29] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those resources that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

ACR

The default Avoidable Cost Rate (ACR) escalation method which had been recommended by the MMU was approved and became effective on February 5, 2013, for the 2016/2017 and subsequent Delivery Years.[30] [31] [32] The 2019/2020 RPM Base Residual Auction was the fourth BRA held under this ACR escalation method change.

The FERC Order also approved updates to the base default ACR values and consolidation of the ACR technology classifications, which are effective for the 2017/2018 and subsequent Delivery Years. The 2019/2020 RPM Base Residual Auction was the third BRA conducted using the revised ACR technology classifications. The default ACR values for the 2019/2020 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2015/2016 for which data were available and applying the most recent ten year annual average rate of change in the Handy-Whitman Index to recalculate the default

29 143 FERC ¶ 61,090 (2013).

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

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

32 142 FERC ¶ 61,092 (2013).

ACR values for 2016/2017 through 2018/2019 prior to estimating the default ACR values for the 2019/2020 Delivery Year.

Demand Resource Rules

Effective January 31, 2013, a third test for determining the Limited DR Reliability Target was implemented by PJM with the goal of limiting the probability of requiring an interruption of longer than six hours, which is the maximum duration of an interruption for a Limited DR product.[33]

Effective with the 2014/2015 Delivery Year, the RPM market design incorporated Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type.[34] Each DR product type is subject to a defined period of availability, a maximum number of interruptions, and a maximum duration of interruptions. The RPM rule changes related to DR product types also include the establishment of a maximum level of Limited DR and a maximum level of Extended Summer DR cleared in the auction, which are defined as a Minimum Annual Resource Requirement and a Minimum Extended Summer Resource Requirement for the PJM region as a whole and LDAs for which a separate VRR curve is established.[35] Annual Resources include generation resources, Annual DR, and EE.

The Minimum Resource Requirements are targets established by PJM to ensure that a sufficient amount of Annual Resources are procured in order to address reliability concerns with the Extended Summer and Limited DR products and to ensure that a sufficient amount of Annual Resources and Extended Summer Resources are procured in order to address reliability concerns with the Limited DR product. The reliability risk associated with relying on either the Extended Summer or Limited DR products results from the fact that reliability must be maintained in all 8,760 hours per year while these resources are required to respond for only a limited number of hours when needed for reliability. The Minimum Annual Resource Requirement is the minimum amount of capacity that PJM will seek to procure from Annual Resources in order to maintain reliability based on a PJM analysis of the probability of needing Limited DR resources.[36]

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33 143 FERC ¶ 61,076 (2013).

34 134 FERC ¶ 61,066 (2011).

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

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

The Minimum Extended Summer Resource Requirement is the minimum amount of capacity that PJM will seek to procure from Annual Resources and Extended Summer DR. In other words, there is a maximum level of Limited DR and a maximum level of Extended Summer DR that PJM will purchase to meet reliability requirements, because additional purchases of these products is not consistent with reliability based on a PJM analysis of the probability of needing Limited DR resources when they are not available. The maximum level of Limited and Extended Summer DR is the difference between the minimum level of Annual Resources and the VRR curve.

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

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

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

Capacity Market Sellers must establish credit if offering any Planned Capacity Resource, Qualified Transmission Upgrade, or an external resource without firm transmission in an RPM Auction. Effective with the 2014/2015 Delivery Year, the RPM market design also included the implementation of credit limited offers, which allow a Capacity Market Seller to specify a Maximum Post-Auction Credit Exposure (MPCE) in dollars for a planned resource using a non-coupled offer type.[37] [38] Capacity Market Sellers utilizing coupled sell offers cannot use the MPCE option. The intent of credit limited offers is to allow Capacity Market Sellers to better manage their credit requirement by specifying the maximum amount of credit they are willing to incur and to provide the service of determining the maximum cleared MW given the MPCE limit. For DR, 20 percent of MW offered used MPCE while for Energy Efficiency (EE) resources, eight percent of MW offered used MPCE.

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

Effective with the 2012/2013 Delivery Year, the RPM credit rate prior to the posting of the BRA results is equal to the greater of $20 per MW-day or 30 percent of the LDA net Cost of New Entry times the number of days in the delivery year, and the RPM credit rate after posting the BRA results is the greater of $20 per MW-day or 20 percent of the LDA resource clearing price for the relevant product type times the number of days in the delivery year.[39] The MPCE option permits participants to offer capacity when they could not otherwise offer capacity based on an uncertain RPM credit rate that could vary with clearing prices.

Effective January 31, 2012, the 2.5 percent holdback was not subtracted from the Minimum Annual and Extended Summer Resource Requirements.[40] The first auction affected was the 2015/2016 BRA. The prior rule required that the Short-Term Resource Procurement Target, or 2.5 percent holdback, be subtracted from all product types including Annual, Extended Summer and Limited DR. Under the old rule, in the case where either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement were binding, the maximum amount of Limited DR would be procured in the Base Residual Auction, leaving none to be procured in Incremental Auctions for the relevant delivery year. Under the new rule, the entire 2.5 percent was subtracted from the amount of Limited DR procured in the BRA, assuming

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37 Letter Order issued in Docket No. ER11-2913-000 (April 13, 2011).

38 PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 88-89.

39 PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 87-88.

40 138 FERC ¶ 61,062 (2012).

either the Minimum Annual Resource Requirement or Minimum Extended Summer Resource Requirement is binding. For example in the 2015/2016 BRA, applying the Short-Term Resource Procurement Target reduced the amount of Limited DR procured by 4,069.4 MW, which is equal to 2.5 percent of 162,777.4, the demand adjusted for FRR.

Effective with the 2017/2018 Delivery Year, the Minimum Annual and Extended Summer Resource Requirements were replaced by Limited and Sub-Annual Resource Constraints.[41] The Limited Resource Constraint limits the quantity of Limited DR that can be procured, and the Sub-Annual Constraint limits the quantity of Limited DR and Extended Summer DR that can be procured. Under the prior rules, the quantity of Limited DR and Extended Summer DR were not capped, as intended, at a fixed MW level. Under the prior rules, if the Minimum Annual Resource Requirement constraint were binding, the Extended Summer and Limited DR products would fill in the balance of capacity needed to meet the VRR curve. The modifications to the rules for the 2017/2018 Delivery Year reduced the impact of Limited and Extended Summer DR on market outcomes compared to what the impact would have been without the rule changes.

Effective March 2, 2014, every DR provider must submit a DR Sell Offer Plan, consisting of a completed template document with certain required information and a DR Offer Certification Form, at least 15 business days prior to an RPM Auction.[42] The DR plan enhancements are meant to standardize the information requirements for offering planned DR, increase the likelihood that offers are based on physical assets and reduce the level of speculative offers. However, the DR plan enhancements did not go far enough to ensure that DR offers are based on physical assets at the time of the offer and therefore did not address the issue of speculative offers that are replaced in incremental auctions.

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

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41 146 FERC ¶ 61,052 (2014).

42 146 FERC ¶ 61,150 (2014).

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

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

Other Changes Affecting Supply and Demand

On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), a final rule setting maximum achievable control technology (MACT) emissions standards for hazardous air pollutants (HAP) from coal-and oil-fired electric utility steam generating units, pursuant to section 112(d) of the Clean Air Act.[43] The rule required compliance by April 16, 2015, with the possibility of one year extensions being granted to individual generation owners.[44]

The State of New Jersey has separately addressed NO_X emissions on peak energy days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD.[45] The rule implemented performance standards effective on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

MMU Methodology

The MMU reviewed the following inputs to and results of the 2019/2020 RPM Base Residual Auction:[46]

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

44 *Id*. at 9465.

45 N.J.A.C. § 7:27–19.

46 Unless otherwise specified, all volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd) for generation resources and as ICAP times the Forecast Pool Requirement (FPR) for Demand Resources and Energy Efficiency Resources. The EFORd values in this report are the EFORd values used in the 2019/2020 RPM Base Residual Auction.

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

- **Net Revenues.** Calculated actual unit-specific net revenue from PJM energy and ancillary service markets for each PJM Generation Capacity Resource for the three year period from 2013 through 2015;[47]

- **Minimum Offer Price Rule (MOPR).** Reviewed requests for Unit-Specific Exceptions, Competitive Entry Exemptions, and Self-Supply Exemptions;

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

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

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

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

- **Maximum EFORd.** Verified that the sell offer EFORd levels were less than or equal to the greater of the one-year EFORd or the five-year EFORd for the period ending September 30, 2015, or reviewed requests for alternate maximum EFORds;

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

- **Clearing Prices.** Verified that the auction clearing prices were accurate, based on submitted offers, the Variable Resource Requirement (VRR) curves, and the Base Capacity Constraints and Base Capacity Demand Resource Constraints;[48]

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47 Net revenue values for the 2019/2020 RPM BRA were calculated consistent with the FERC order effective at the time. *See FirstEnergy Solutions Corp. v. PJM Interconnection, L.L.C.*, 148 FERC ¶ 61,140 (2014).

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

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

Market Structure Tests

As shown in Table 4, all participants in the RTO, EMAAC, ComEd, and BGE RPM markets failed the TPS test.[49] 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 defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price. Market power mitigation was applied to the Base Capacity sell offers of 34 Generation Capacity Resources, including 3,116.5 MW and to a small number of Capacity Performance sell offers in the 2019/2020 RPM Base Residual Auction.[50] All other offers were competitive.

In applying the market structure test, the relevant supply for the RTO market includes all supply from generation resources offered at less than or equal to 150 percent of the RTO clearing price resulting from offer-capped offers for all supply.[51] The relevant supply for the constrained LDA markets includes the incremental supply from generation resources inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the clearing price for the constrained LDA resulting from offer-capped offers for all supply. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint and meet the VRR curve for the LDA.

Table 4 presents the results of the TPS test and the one pivotal supplier test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_3). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant

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

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

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

ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.[52]

Table 4 RSI results: 2019/2020 RPM Base Residual Auction[53]

	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1

Offer Caps and Offer Floors

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data to the MMU by 120 days prior to the 2019/2020 RPM Base Residual Auction.[54] Market power mitigation measures are applied to Existing Generation Capacity Resources such that the sell offer is set equal to the defined offer cap when the Capacity Market Seller fails the market structure test for the auction, the submitted sell offer exceeds the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.[55] For RPM Base Residual Auctions, for Base Capacity, offer caps are defined as avoidable costs less PJM market revenues, or opportunity costs. For Capacity Performance Resources, offer caps as defined as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the Base Residual Auction for such Delivery Year unless avoidable costs exceed this level, or opportunity costs.

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

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

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

55 OATT Attachment DD § 6.5.

Table 5 shows the zonal net CONE times B offer caps for the 2018/2019 and 2019/2020 RPM Base Residual Auctions. In all zones except EKPC, the net CONE times B offer cap values decreased from the 2018/2019 RPM Base Residual Auction.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the Delivery Year.[56] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[57]

The default ACR values for the 2019/2020 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2015/2016 for which data were available and applying the most recent ten year annual average rate of change in the Handy-Whitman Index to recalculate the default ACR values for 2016/2017 through 2018/2019 prior to estimating the default ACR values for the 2019/2020 Delivery Year.[58]

Effective for the 2018/2019 and subsequent Delivery Years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[59] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and

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56 OATT Attachment DD § 6.8 (b).

57 OATT Attachment DD § 6.8 (a).

58 The default Avoidable Cost Rate (ACR) escalation method which had been recommended by the MMU was approved and became effective on February 5, 2013 for the 2016/2017 and subsequent Delivery Years. See 142 FERC ¶ 61,092 (2013).

59 151 FERC ¶ 61,208.

2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

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

As shown in Table 5, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources that submitted Base Capacity offers, of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values. No generation resources elected to use the retirement ACR in the 2019/2020 BRA. Unit-specific ACR based offer caps were calculated for 34 generation resources (6.7 percent) including 34 generation resources (6.7 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and zero generation resource (0.0 percent) without an APIR component. Of the 505 generation resources offered as Base Capacity, seven generation resources had opportunity cost-based offer caps, nine Planned Generation Capacity Resources had uncapped offers, while the remaining 284 generation resources were price takers.[60]

As shown in Table 3, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources that submitted Capacity Performance offers, none of which were based on the technology specific default (proxy) ACR values. Unit-specific ACR-based offer caps were calculated for 25 generation resources (2.5 percent) including 17 generation resources (1.7 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and eight generation resources (0.8 percent) with an APIR component and no CPQR component. Of the 1,003 generation resources offered as Capacity Performance, 888 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 14 Planned Generation

[60] Planned Generation Capacity Resources are subject to different market power mitigation rules than Existing Generation Capacity Resources. For RPM rules on mitigation, see OATT Attachment DD § 6.5 (a) (ii). For the definition of Planned Generation Capacity Resource, see "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.70.

Capacity Resources had uncapped offers, two generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 74 generation resources were price takers.

As shown in Table 7, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources.

The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources.[61] The maximum APIR effect ($1,104.93 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR.

The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

The weighted average offer cap for Base Capacity Resources without an APIR component, including units for which the default value was selected, was $33.97 per MW-day.[62] There were no unit-specific ACR based offer caps without an APIR component submitted for Capacity Performance Resources.

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 8, of the 14,097.2 ICAP MW of MOPR Competitive Entry Exemption requests, all requests were granted. Of the 6,212.9 MW offered for MOPR Screened Generation Resources for which exemptions were sought, 5,259.5 MW cleared and 953.4 MW did not clear. There was a small number

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61 The net revenue offset for an individual unit could exceed the corresponding ACR. In that case, the offer cap would be zero.

62 Effective for the 2017/2018 and subsequent Delivery Years, the default ACR values include no APIR.

of additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied.[63]

Tables for Offer Caps and Offer Floors

Table 5 Net CONE times B: 2018/2019 and 2019/2020 RPM Base Residual Auctions

	2018/2019					2019/2020					Change				
Zone	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)	Gross CONE ($ per MW-Day)	Net E&AS Revenue ($ per MW-Day)	Net CONE ($ per MW-Day)	Balancing Ratio	Net CONE Times B ($ per MW-day)
AECO	$362.19	$88.87	$273.32	0.85	$232.32	$364.30	$84.52	$279.78	0.81	$226.62	$2.10	($4.35)	$6.46	(0.04)	($5.70)
AEP	$353.15	$82.55	$270.60	0.85	$230.01	$362.47	$96.93	$265.54	0.81	$215.09	$9.32	$14.38	($5.06)	(0.04)	($14.92)
AP	$353.15	$104.82	$248.33	0.85	$211.08	$362.47	$128.99	$233.48	0.81	$189.12	$9.32	$24.16	($14.85)	(0.04)	($21.96)
ATSI	$353.15	$98.68	$254.47	0.85	$216.30	$362.47	$115.84	$246.63	0.81	$199.77	$9.32	$17.16	($7.84)	(0.04)	($16.53)
BGE	$356.99	$136.36	$220.63	0.85	$187.54	$366.94	$165.54	$201.39	0.81	$163.13	$9.95	$29.19	($19.24)	(0.04)	($24.41)
ComEd	$353.15	$53.20	$299.95	0.85	$254.96	$362.47	$55.70	$306.77	0.81	$248.48	$9.32	$2.50	$6.82	(0.04)	($6.48)
DAY	$353.15	$89.86	$263.30	0.85	$223.81	$362.47	$103.43	$259.04	0.81	$209.82	$9.32	$13.58	($4.26)	(0.04)	($13.99)
DEOK	$353.15	$77.84	$275.31	0.85	$234.01	$362.47	$94.01	$268.46	0.81	$217.45	$9.32	$16.17	($6.85)	(0.04)	($16.56)
DLCO	$353.15	$84.67	$268.48	0.85	$228.21	$362.47	$94.78	$267.69	0.81	$216.83	$9.32	$10.12	($0.79)	(0.04)	($11.38)
DPL	$362.19	$120.27	$241.92	0.85	$205.63	$364.30	$119.34	$244.96	0.81	$198.42	$2.10	($0.94)	$3.04	(0.04)	($7.21)
Dominion	$353.15	$80.70	$272.45	0.85	$231.58	$362.47	$84.06	$278.41	0.81	$225.51	$9.32	$3.36	$5.96	(0.04)	($6.07)
EKPC	$353.15	$133.93	$219.22	0.85	$186.34	$362.47	$108.90	$253.57	0.81	$205.39	$9.32	($25.03)	$34.35	(0.04)	$19.05
External	$357.33	$75.84	$281.49	0.85	$239.27	$365.17	$85.62	$279.55	0.81	$226.44	$7.84	$9.78	($1.94)	(0.04)	($12.83)
JCPL	$362.19	$102.23	$259.96	0.85	$220.97	$364.30	$119.27	$245.02	0.81	$198.47	$2.10	$17.04	($14.94)	(0.04)	($22.50)
Met-Ed	$356.99	$91.72	$265.26	0.85	$225.47	$366.97	$106.89	$260.08	0.81	$210.66	$9.98	$15.17	($5.18)	(0.04)	($14.81)
PECO	$362.19	$92.52	$269.67	0.85	$229.22	$364.30	$104.94	$259.36	0.81	$210.08	$2.10	$12.42	($10.31)	(0.04)	($19.14)
PENELEC	$356.99	$146.23	$210.76	0.85	$179.15	$366.97	$213.39	$153.58	0.81	$124.40	$9.98	$67.16	($57.18)	(0.04)	($54.75)
PPL	$356.99	$90.28	$266.71	0.85	$226.70	$366.97	$107.56	$259.41	0.81	$210.12	$9.98	$17.29	($7.30)	(0.04)	($16.58)
PSEG	$362.19	$83.12	$279.07	0.85	$237.21	$364.30	$81.02	$283.28	0.81	$229.46	$2.10	($2.10)	$4.21	(0.04)	($7.75)
Pepco	$356.99	$122.16	$234.82	0.85	$199.60	$366.94	$138.83	$228.11	0.81	$184.77	$9.95	$16.66	($6.71)	(0.04)	($14.83)
RECO	$362.19	$85.73	$276.46	0.85	$234.99	$364.30	$87.24	$277.06	0.81	$224.42	$2.10	$1.50	$0.60	(0.04)	($10.57)

Table 6 ACR statistics: 2019/2020 RPM Base Residual Auction

	Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%
Unit specific ACR (APIR)	34	6.7%	8	0.8%
Unit specific ACR (APIR and CPQR)	0	0.0%	17	1.7%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost	7	1.4%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%
Uncapped planned uprates and default ACR	0	0.0%	0	0.0%
Uncapped planned uprates and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%
Uncapped planned uprates and price taker	0	0.0%	0	0.0%
Uncapped planned generation resources	9	1.8%	14	1.4%
Existing generation resources as price takers	284	56.2%	74	7.4%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%

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

Table 7 APIR statistics: 2019/2020 RPM Base Residual Auction[64] [65] [66]

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$89.05	
Net revenues	$150.86	
Offer caps	$33.97	
APIR units		
ACR	$341.40	$499.18
Net revenues	$65.48	$167.61
Offer caps	$271.22	$323.27
APIR	$230.67	$375.38
CPQR	$0.00	$1.53
Maximum APIR effect	$1,104.93	$1,104.93

[64] The weighted average offer cap can be positive even when the weighted average net revenues are higher than the weighted average ACR because the unit-specific offer caps are never less than zero. On a unit basis, if net revenues are greater than ACR the offer cap is zero.

[65] For reasons of confidentiality, the APIR statistics do not include opportunity cost-based offer cap data.

[66] Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2019/2020 BRA, waste coal resources are included in the coal fired category.

Table 8 MOPR statistics: 2019/2020 RPM Base Residual Auction[67]

Request Type	Requested ICAP (MW)	Granted ICAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)
Competitive Entry Exemption	12,270.0	12,270.0	4,671.0	4,515.1	3,561.7
Self-Supply Exemption	1,827.2	1,827.2	1,779.5	1,697.8	1,697.8
Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
Total	14,097.2	14,097.2	6,450.5	6,212.9	5,259.5

Competitive Capacity Performance Offers

The competitive offer of a Capacity Performance resource is based on a market seller's expectations on a number of variables, some of which are resource specific:[68] the resource's net going forward costs (Net ACR); and the expectation about the resource's performance during performance assessment hours (A) in the delivery year.

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the expectations about the number of performance assessment hours (PAH) in a delivery year (H) where the resource is located; the expected level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of bonus performance payment rate (CPBR) compared to the non-performance charge rate (PPR). This depends on the number of underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[69]

Attachment B explains the derivation of the competitive offer of a Capacity Performance resource. The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

67 There were a small number of additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers not reported as a result of PJM confidentiality rules.

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

69 OATT Attachment DD § 10A (d).

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

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

If the expectations of a market seller on any of these variables are different from the assumptions stated above, the competitive offer of such a resource is different from Net CONE times B. This is illustrated in an example using the Net CONE and average balancing ratio value used for the default offer cap (81 percent) published by PJM for the 2019/2020 BRA.

Example Competitive Offer Calculation

Consider a resource with a Net ACR of $50,000 per ICAP MW per year, or $136.61 per ICAP MW per day in the AEP zone, with an expected average performance of 78 percent during performance assessment hours. Without a capacity commitment, the resource would have earned bonus payments during all the performance assessment hours for its entire performance. If the unit expects 30 performance assessment hours and expects that 20 percent of underperformance MWh are excused on average (in other words, bonus performance payment rate is equal to 80 percent of the non-performance charge rate), its expected energy only bonus payments are calculated as:

Energy only bonus revenues = $CPBR \times H \times \bar{A}$

Using a bonus performance rate of 0.8 times the non-performance charge rate for the AEP zone, CPBR ($ per MWh) = $3,230.7 × 0.8 = $2,584.6 per MWh

Energy only bonus revenues = 2,584.6 ($/MWh) × 30 (hours/year) × 0.78

= $60,479 per MW–year

The Net ACR of the resource ($50,000 per MW-year) is less than its expected energy only bonus revenues ($60,479 per MW-year). The competitive offer of such a resource is:

$$p = CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A})$$

In other words, the competitive offer is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned ($CPBR \times H \times \bar{A}$) and the non-performance charges it would incur by taking on the capacity obligation ($PPR \times H \times (\bar{B} - \bar{A})$). This is because its expected average performance at 78 percent is less than the expected average balancing ratio of 81 percent. The competitive offer is calculated as:

$$p = (0.8 \times PPR) \times 30 \times 0.78 + PPR \times 30 \times (0.81 - 0.78)$$

p = $63,387 per MW-year or $173.18 per MW-day[70]

In comparison, the default offer cap for the resource, Net CONE times B is:

Default offer cap = $78,722 per MW-year or $215.09 per MW-day

This example illustrates how, when a market seller's expectation on just one variable is different from the assumptions used in the default offer cap calculation (in this case the bonus payment rate is estimated as 80 percent of the non-performance charge rate), the competitive offer of a resource is lower than the default offer cap.

As illustrated in the example above, a market seller can similarly have different expectations for the other variables in the competitive offer calculation: A, B and H. These expectations can lead to competitive offers below Net CONE times B, the default offer cap. The offers below the default offer cap indicate that market sellers of Capacity Performance resources in PJM expect the number of performance assessment hours (H) to be less than 30, the expected average performance of resources (A) to increase under the Capacity Performance framework, and expect locational events where balancing ratio (B) is expected to be different from the historical average of 81 percent that PJM used for the default offer cap calculation.

Table 9 shows sample calculations for a Low ACR resource in the AEP, ATSI, Dayton, DEOK and PPL zones in PJM all of which cleared at the rest of RTO price of $100.00 per MW-day in the 2019/2020 BRA. The competitive offers calculated in Table 9 are close to the clearing price observed for these zones in the 2019/2020 BRA. The assumptions used for the competitive offer calculation in Table 9 are:

- H = 20;

70 The year 2020 is a leap year, so to convert from $ per MW-day to $ per MW-year, the multiplier is 366.

- Expected average B = 81%;
- Expected average A = 85%;
- Expected average bonus payment rate = 70 percent of the non-performance charge rate.

Table 9 Competitive offers for hypothetical resources in the rest of RTO zones[71]

Zone	Net Cone ($ per MW-Day) (ICAP Terms)	Balancing Ratio, B (%)	Expected number of Performance Assessment Hours, H (hours per year)	Unit specific Availability A (%)	Non-Performance Charge Rate (PPR) in $ per MWh (Net CONE *(365/30))	Capacity Performance Bonus Rate (CPBR) assumed to be 70% of PPR	Expected Bonus Revenues as an Energy Only Resource ($ per MW-year)	Competitive Offer of a Low ACR resource using CPBR = 70% of PPR	Default Offer Cap (Net CONE*B)
AEP	$265.54	81%	20	85%	$3,230.7	$2,261.5	$38,446	$100.10	$215.09
ATSI	$246.63	81%	20	85%	$3,000.7	$2,100.5	$35,708	$92.97	$199.77
DAY	$259.04	81%	20	85%	$3,151.7	$2,206.2	$37,505	$97.65	$209.82
DEOK	$268.46	81%	20	85%	$3,266.3	$2,286.4	$38,869	$101.20	$217.45
PPL	$259.41	81%	20	85%	$3,156.2	$2,209.3	$37,558	$97.79	$210.12

Table 10 shows sample calculations for a Low ACR resource in the PSEG, DPL and JCPL zones in PJM all of which cleared at the EMAAC price of $119.77 per MW-day in the 2019/2020 BRA. The competitive offers calculated in Table 10 are close to the clearing price observed for these zones in the 2019/2020 BRA. The assumptions used for the competitive offer calculation in Table 10 are:

- H = 20;
- Expected average B = 85%;
- Expected average A = 90%;
- Expected average bonus payment rate = 80 percent of the non-performance charge rate.

71 The Non Performance Charge Rate is defined in the PJM OATT as Net CONE for the LDA (in $/MW ICAP-day) times 365 divided by 30, regardless of whether the delivery year includes a leap year. See OATT Attachment DD § 10A (e).

Table 10 Competitive offers for hypothetical resources in the EMAAC zones

Zone	Net Cone ($ per MW-Day) (ICAP Terms)	Balancing Ratio, B (%)	Expected number of Performance Assessment Hours, H (hours per year)	Unit specific Availability A (%)	Non-Performance Charge Rate (PPR) in $ per MWh (Net CONE *(365/30))	Capacity Performance Bonus Rate (CPBR) assumed to be 80% of PPR	Expected Bonus Revenues as an Energy Only Resource ($ per MW-year)	Competitive Offer of a Low ACR resource using CPBR = 80% of PPR	Default Offer Cap (Net CONE*B)
PSEG	$283.28	85%	20	90%	$3,446.6	$2,757.3	$49,630.7	$128.07	$229.46
DPL	$244.96	85%	20	90%	$2,980.3	$2,384.3	$42,917.0	$110.75	$198.42
JCPL	$245.02	85%	20	90%	$2,981.1	$2,384.9	$42,927.5	$110.77	$198.47

While Table 9 and Table 10 illustrate a set of assumptions that lead to competitive offer prices close to the observed clearing prices, it is important to note that the assumptions for the variables involved (A, B, H and bonus payment dilution) can be wide ranging and unit specific depending on a market seller's view of the system outcomes as well as the performance of its own resources. These examples are meant to illustrate that offers below the tariff defined offer cap of Net CONE times B are competitive offers. It is also important to remember that market sellers have had no experience of operating under the Capacity Performance framework and that the assumptions will evolve as they gain more experience with the implementation of the Capacity Performance design.

Bonus Performance Payment Rate Dilution

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

Dilution of bonus performance generally leads to lower competitive offers, since the opportunity of earning bonuses as an energy only resource decreases proportionately with a lower bonus performance payment rate. The pricing in the capacity market is a direct reflection of the market sellers' expectation of PJM's implementation of the Capacity Performance design. It is important to implement the no-excuses approach as ordered by the Commission and ensure that resources can only meet their obligation by actually performing during the most critical times.

Generation Capacity Resource Changes

As shown in Table 5, Base Capacity offers, including non-coupled and coupled offers, were submitted for 505 generation resources and Capacity Performance offers, including non-coupled and coupled offers, were submitted for 1,003 generation resources in the 2019/2020 RPM Base Residual Auction. Coupled offers were submitted for 308 generation resources, Base Capacity non-coupled offers were submitted for 197 generation resources (505 minus 308), and Capacity Performance non-coupled offers were submitted for 695 generation resources (1,003 minus 308), resulting in 1,200 distinct generation resources offered in the 2019/2020 RPM Base Residual Auction compared to 1,189 generation resources offered in the 2018/2019 RPM Base Residual Auction, or a net increase of 11 generation resources. This was a result of 43 additional generation resources offered offset by 32 fewer generation resources offered.

The 43 additional generation resources offered consisted of 39 new resources (6,685.5 MW), three additional resources imported (162.5 MW), and one resource that was unoffered in the 2018/2019 BRA (2.9 MW).[72]

The 39 new Generation Capacity Resources consisted of 18 solar resources (152.3 MW), seven combined cycle resources (5,925.6 MW), five diesel resources (83.2 MW), five wind resources (73.0 MW), and four CT resources (451.4 MW).

The 32 fewer generation resources offered consisted of 15 fewer resources resulting from aggregation of RPM resources, six deactivated resources (772.8 MW), five external resources not offered (956.6 MW), resources excused from offering for reasons other than retirement, and Planned Generation Capacity Resources not offered.[73] In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2018/2019 BRA: two steam resources (148.9 MW) and one combustion turbine (0.8 MW). Table 11 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2018/2019 BRA and the 2019/2020 BRA.

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

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

Table 11 Generation Capacity Resource deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
SUNOIL SUNOIL GEN UNIT	EMAAC	49.5	08-May-15	13-May-19
GARRETT WF	MAAC	0.5	07-Aug-15	01-Dec-15
PERRYMAN CT 2	BGE	51.0	02-Oct-15	01-Feb-16
FAUQUIER LF	RTO	2.0	25-Nov-15	31-Jan-16
AVON LAKE 7	ATSI Cleveland	94.0	01-Dec-15	16-Apr-16
OYSTER CREEK 1	EMAAC	607.7	01-Dec-15	31-Dec-19

RTO Market Results

Total Offers

Table 12 shows total RTO offer data for the 2019/2020 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.[74] [75] As shown in Table 15, total internal RTO unforced capacity (UCAP) increased 4,802.7 MW (2.5 percent) from 195,262.8 MW in the 2018/2019 RPM BRA to 200,065.5 MW.

When comparing UCAP MW levels from one auction to another, two variables, capacity modifications and EFORd changes, need to be considered. The net internal capacity change attributable to capacity modifications can be determined by holding the EFORd level constant at the prior auction's level. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications. The 4,802.7 MW increase in internal capacity was a result of net generation capacity modifications (cap mods) (3,802.2 MW), net DR capacity changes (-326.8 MW), net EE modifications (204.3 MW), the EFORd effect due to lower sell offer EFORds (1,058.9 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (64.1 MW).[76]

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

75 Maps of the LDAs can be found in the *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

76 Prior to the 2018/2019 Delivery Year, the UCAP value of a load management product is equal to the ICAP value multiplied by the Demand Resource (DR) Factor and the Forecast Pool Requirement (FPR). Effective for the 2018/2019 and subsequent Delivery Years, the UCAP value of a load management product is equal to the ICAP value multiplied by the FPR. For the 2018/2019 BRA, this conversion factor was 1.0835. For the 2019/2020 BRA, this conversion factor was 1.0881. The DR Factor was designed to reflect the difference in losses that occur on the distribution system between the meter where demand is measured and the transmission

The net generation capacity modifications reflect new and reactivated generation, deactivations, and cap mods to existing generation. Total internal RTO unforced capacity includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources for the 2019/2020 RPM Base Residual Auction, excluding external units, and also includes owners' modifications to installed capacity (ICAP) ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[77] The ICAP of a unit may only be reduced through a cap mod if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the planning period in question.[78] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity modifications, DR plan changes, and EE plan changes were the result of owner reevaluation of the capabilities of their generation, DR and EE, at least partially in response to the incentives and penalties contained in RPM as modified by CP changes.

After accounting for FRR committed resources and for imports, total RPM capacity was 190,419.4 MW compared to 186,373.0 MW in the 2018/2019 RPM Base Residual Auction.[79] FRR volumes decreased by 84.8 MW, and imports decreased by 841.1 MW. Of the 4,762.3 MW of imports, 418.9 MW were committed to an FRR capacity plan and 4,343.4 MW were offered in the auction, of which 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 percent) were from MISO. RPM capacity was reduced by exports of 1,288.6 MW, an increase of 6.3 MW from the 2018/2019 RPM Base Residual Auction. Of total exports, 671.0 MW (52.1 percent) were to the NYISO, 539.5 MW (41.9 percent) were to MISO, and 78.1 MW (6.1 percent) were to Duke Energy Carolinas.

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system. The FPR multiplier is designed to recognize the fact that when demand is reduced by one MW, the system does not need to procure that MW or the associated reserve. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 6, Section B. See also PJM. "Manual 20: PJM Resource Adequacy Analysis," Revision 06 (August 1, 2015), pp. 12-14.

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

78 PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 11 (March 5, 2014), p. 11. The manual states "the end of the next Delivery Year."

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

In addition, RPM capacity was reduced by 322.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and by 1,670.2 MW which were excused from the RPM must offer requirement, an increase of 605.0 MW from the 2018/2019 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement (891.1 MW), the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (281.0 MW), partial year ownership (476.0 MW), and capacity resource status change (22.1 MW).[80] Subtracting 123.7 MW of FRR optional volumes not offered, an increase of 73.9 MW from the 2018/2019 RPM Base Residual Auction, and 1,475.3 MW of DR and EE not offered, resulted in 185,539.5 MW that were available to be offered in the RPM Auction, an increase of 5,641.9 MW from the 2018/2019 RPM Base Residual Auction.[81] [82] After accounting for these factors, 0.0 MW were not offered and unexcused in the RPM Auction.

Offered MW increased 5,648.3 MW from 179,891.2 MW to 185,539.5 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 3,515.0 MW from 160,607.4 MW to 157,092.4 MW.[83] The RTO Reliability Requirement adjusted for FRR obligations is calculated as the RTO forecast peak load times the Forecast Pool Requirement (FPR), less FRR UCAP obligations. The FPR is calculated as (1+Installed Reserve Margin) times (1-Pool Wide Average EFORd), where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability.[84] The 3,515.0 MW decrease

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

81 FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 123.7 MW are a combination of excess volumes included in the sales cap amount which were not offered in the auction and volumes above the sales cap amount which were not permitted to offer in the auction.

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

83 The maximum capacity within a coupled segment group was included in the offered capacity values reported.

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

in the RTO Reliability Requirement adjusted for FRR obligations from the 2018/2019 RPM Base Residual Auction was a result of a 3,860.0 MW decrease in the RTO Reliability Requirement not adjusted for FRR offset by a 345.0 MW decrease in the FRR obligation, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity decreased 4,229.9 MW from the 2018/2019 RPM Base Residual Auction to 157,188.5 MW. The 3,860.0 MW decrease in the RTO Reliability Requirement was a result of a 4,583.1 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2018/2019 level offset by a 723.1 MW increase attributable to the change in the FPR. The increase in the FPR from the 2018/2019 RPM Base Residual Auction is a result of an increase in the IRM offset by an increase in the Pool Wide Average EFORd.

CP Generation Offers

Table 13 shows RTO CP generation offer data for the 2019/2020 RPM Base Residual Auction. Internal RTO generation capacity was 184,479.8 MW. After accounting for FRR committed generation resources of 13,766.3 MW and for imports of 4,677.6 MW, RPM generation capacity was 175,391.1 MW. RPM generation capacity was reduced by 1,288.6 MW of exports, 123.7 MW of FRR optional volumes not offered, 1.670.2 MW excused from the RPM must offer requirement, 1,042.8 MW excused from the CP must offer requirement, 322.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement, 3,902.4 MW of Intermittent Resources and Capacity Storage Resources which were not subject to the CP must offer requirement, and 0.0 MW of generation resources deemed ineligible by PJM to offer as CP.

Resource Constraints

Effective for the 2017/2018 Delivery Year, the Minimum Annual and Extended Summer Resource Requirements were replaced by Limited and Sub-Annual Resource Constraints. The Limited Resource Constraint limits the quantity of Limited DR that can be procured, and the Sub-Annual Constraint limits the quantity of Limited DR and Extended Summer DR that can be procured. Under the prior rules, the quantity of Limited DR and Extended Summer DR were not capped in this way. Under the prior rules, if the Minimum Annual Resource Requirement were a binding constraint, the Extended Summer and Limited DR products could fill in the balance of capacity needed to meet the VRR curve. These modifications reduced the impact of Limited and Extended Summer DR on market outcomes.

Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are defined for each modeled LDA, replacing the Sub-Annual Resource Constraint and Limited Resource Constraint.

PJM's auction clearing mechanism will result in a lower price for Base Capacity Resources if the MW of Base Capacity Resources that would otherwise clear the auction, including Base Capacity DR/EE Resources, are more than the Base Capacity Resource Constraint that PJM defines as the maximum for reliability. In that case, the auction clearing mechanism will select Base Capacity Resources and Base Capacity DR/EE Resources that are less expensive than the clearing price that would otherwise result, due to the defined Base Capacity Resource Constraint. PJM's auction clearing mechanism will also result in a lower price for Base Capacity DR/EE Resources if the MW of Base Capacity DR/EE Resources that would otherwise clear the auction are more than the Base Capacity Demand Resource Constraint that PJM defines for reliability. In that case the auction clearing mechanism will select Base Capacity DR/EE Resources that are less expensive than the clearing price that would otherwise result, due to the defined Base Capacity Demand Resource Constraint.

In cases where one or both of the resource constraints bind, resources selected to meet the resource constraints will receive a price decrement to the system marginal price, in addition to any locational price adders needed to resolve locational constraints.

The Base Capacity Resource Constraint was a binding constraint for the RTO in the 2019/2020 BRA. As shown in Figure 1, the resource clearing price for Capacity Performance Resources for the RTO was $100.00 per MW-day, and the resource clearing price for Base Capacity Resources and Base Capacity DR/EE Resources was $80.00 per MW-day.

Clearing Results

The Net Load Price that load serving entities (LSEs) will pay is equal to the Final Zonal Capacity Price less the final Capacity Transfer Rights (CTR) credit rate.[85] As shown in Table 12, the preliminary Net Load Price is $96.77 per MW-day in the RTO.

As shown in Table 12, the 165,814.4 MW of cleared and make whole generation and DR for the entire RTO, resulted in a reserve margin of 22.9 percent and a net excess of 8,722.0 MW over the reliability requirement of 157,092.4 MW (Installed Reserve Margin (IRM) of 16.5 percent).[86] [87] [88] [89] Net excess increased 2,453.9 MW from the net excess of

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

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

6,268.1 MW in the 2018/2019 RPM Base Residual Auction. Inclusion of cleared EE Resources in the calculations on the supply side and as an add back on the demand side results in a calculated reserve margin of 22.6 percent and a net excess of 8,345.7 MW over the reliability requirement of 157,092.4 MW. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Capacity Performance Resources of $100.00 per MW-day.

If the market clears on a nonflexible supply segment, a sell offer that specifies a minimum block MW value greater than zero, the Capacity Market Seller will be assigned make whole MW equal to the difference between the sell offer minimum block MW and the sell offer cleared MW quantity if that solution to the market clearing minimizes the cost of satisfying the reliability requirements across the PJM region.[90] The make whole payment for partially cleared resources equals the make whole MW times the clearing price. A more efficient solution could include not selecting a nonflexible segment from a lower priced offer and accepting a higher priced sell offer that does not include a minimum block MW requirement.[91] [92] The market results in the 2019/2020 BRA included make whole MW and payments resulting from partially cleared resources. Make whole MW and payments can also occur for resources electing the New Entry Price Adjustment (NEPA) or Multi-Year Pricing Option.[93] [94] If an offer clears in an auction under either option and if a qualifying resource does not clear in the two subsequent BRAs, the process specified in the Tariff is triggered, and the resource is

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and subsequent Delivery Years, the net excess under RPM is calculated as cleared generation and DR capacity plus make whole MW less the reliability requirement.

87 The IRM increased from 15.7 percent in the 2018/2019 RPM Base Residual Auction to 16.5 percent in the 2019/2020 RPM Base Residual Auction.

88 The 22.9 percent reserve margin does not include EE on the supply side or the EE add back on the demand side. This is how PJM calculates the reserve margin.

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

90 OATT Attachment DD § 5.14 (b).

91 OATT Attachment DD § 5.12 (a).

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

93 OATT Attachment DD § 5.14 (c) (2).

94 OATT Attachment DD § 6.8 (a).

awarded a make whole payment.[95] The market results in the 2019/2020 BRA did not include make whole MW or payments related to NEPA or Multi-Year Pricing Option.

Table 16 shows offered and cleared MW by LDA, resource type, and offer/product type in the 2019/2020 RPM Base Residual Auction. Of the 145,558.1 MW of non-coupled generation offers, 5,023.0 MW were for the Base Capacity product. Offers of 26,506.2 MW for CP generation were coupled with Base Capacity generation. Of the 7,155.2 MW of non-coupled DR offers, 6,656.9 MW were for the Base Capacity DR product. Of the 1,067.5 MW of non-coupled EE offers, 526.1 MW were for the Base Capacity EE product. The fact that 4,223.3 MW of CP DR offers were coupled with Base DR offers and 582.1 MW of CP EE offers were coupled with Base EE offers provides evidence that providers are willing to offer a CP demand side product.

Table 17 shows the weighted average sell offer prices by LDA, resource type, and offer/product type. For the coupled DR offers, the offers for Capacity Performance Resources were greater than the offers for Base Capacity Resources. The Capacity Market Seller must specify a sell offer price of at least $0.01 per MW-day more for the less limited product type within a coupled segment group.

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

The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. When the mitigation rule changes for DR and EE resources became effective on November 1, 2009, with the result that DR and EE resources were no longer subject to market power mitigation, the RPM market structure and parameters were different than they are under the current rules. In 2009, there was one product defined for capacity, and there were no resource constraints defined. Particularly in LDAs with few suppliers, there is now the potential for DR and EE providers to exercise market power and affect the clearing price.

Table 18 shows the offered MW by resource type, offer/product type, and price range as percent of net CONE times B in the 2019/2020 RPM Base Residual Auction. Non-coupled

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

Capacity Performance generation offers between $0 per MW-day and 50 percent of net CONE times B increased by 13,787.6 MW from the 2018/2019 RPM Base Residual Auction.

Table 19 shows cleared MW by zone and fuel source. Of the 172,071.2 MW offered for generation resources, 155,442.8 MW cleared (90.3 percent). Of the 167,305.9 cleared MW in the entire RTO, 27,387.9 MW (16.4 percent) cleared in Dominion, followed by 22,971.4 MW (13.7 percent) in ComEd and 16,909.9 MW (10.1 percent) in AEP. Of the 155,442.8 cleared MW for generation resources in the entire RTO, 71,582.4 MW (46.1 percent) were gas resources, followed by 43,574.2 MW (28.1 percent) from coal resources and 25,888.8 MW (16.7 percent) from nuclear resources.

The 18,210.0 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 18,210.0 uncleared MW in the entire RTO, 135.2 MW were EE offers, 1,470.0 MW were DR offers, and the remaining 16,604.8 MW were generation offers. Table 20 presents details on the generation offers that did not clear. Of the 16,604.8 MW of uncleared generation offers, 10,341.2 MW (62.3 percent) were for generation resources greater than 40 years old, and 6,263.6 MW (37.7 percent) were for generation resources less than or equal to 40 years old.

Table 21 shows the auction results for the prior two Delivery Years for the generation resources that did not clear some or all MW in the 2019/2020 BRA. Of the 277 generation resources that did not clear 16,604.8 MW in the 2019/2020 BRA, 167 of those generation resources did not clear 7,889.6 MW in RPM Auctions for the 2018/2019 Delivery Year. Of those 167 generation resources that did not clear MW in RPM Auctions for the 2019/2020 and 2018/2019 Delivery Years, 63 of those generation resources did not clear 3,487.8 MW in RPM Auctions for the 2017/2018 Delivery Year. Thus, 7,889.6 MW of capacity did not clear in two sequential auctions, but 3,487.8 MW did not clear in three sequential auctions.

Capacity Transfer Rights

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

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

In the 2019/2020 RPM Base Residual Auction, EMAAC had 4,242.2 MW of CTRs with a total value of $30,695,796, ComEd had 2,355.1 MW of CTRs with a total value of $88,584,307, and BGE had 4,720.3 MW of CTRs with a total value of $518,289.

Constraints in RPM Markets: CETO/CETL

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, PJM does a load deliverability analysis for each LDA.[96] The first step in this process is to determine the transmission import requirement in to an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the Capacity Emergency Transfer Limit (CETL), which is also expressed in unforced megawatts. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning (RTEP) Process. However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[97]

Under the Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder

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96 PJM. "Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Revision 33 (May 5, 2016), p. 57. Manual 14B indicates that all "electrically cohesive load areas" are tested.

97 PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), p. 11.

in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of these three tests.[98] In addition, PJM may establish a constrained LDA even if it does not qualify under these tests if PJM finds that "such is required to achieve an acceptable level of reliability."[99] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

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

Table 22 shows the CETL and CETO values used in the 2019/2020 study compared to the 2018/2019 values. The same LDAs were modeled in the 2018/2019 BRA and 2019/2020 BRA. The only CETL value for the modeled LDAs that changed significantly was PPL. The PPL CETL increased due to "the addition of a new 230/138 kV Wescosville transformer in parallel with the existing 230/138kV Wescosville transformer, which was the facility that limited additional imports in the PPL LDA in last year's CETL analysis."[100]

CETL for border LDAs like ComEd include import capability from MISO as well as from PJM. The import capability was reduced as a result of transmission upgrades in MISO that limited power flows originating from MISO, and an increase in firm transmission

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

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

100 See PJM "2019/2020 RPM Base Residual Auction Planning Period Parameters" <http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-rpm-bra-planning-parameters-report.ashx> (February 8, 2016).

service for transmission into PJM from MISO. Most of the firm transmission service was related to the import of capacity from MISO into PJM but the firm transmission service affected import transmission paths into ComEd. The increase in capacity imports from MISO meant an increase in the associated firm transmission service required which meant reduced CETL for the ComEd LDA and higher prices for the ComEd LDA. The increase in capacity imports from MISO was modeled as capacity imports into the rest of RTO and resulted in lower prices in the rest of RTO.

The Price Impacts of Constraints in the RPM Market

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

There were three locationally binding constraints in the 2019/2020 BRA which resulted in demand clearing in a locationally constrained LDA which did not clear in the RTO market or in contiguous or parent LDAs and at a higher price than in contiguous or parent LDAs. The result was to shift the demand curve in the RTO market to the left along the upwardly sloping supply curve and to reduce the price in the RTO market. The price impact is the result both of the size of the shift of the demand curve and the slope of the supply curve. The larger the shift in the demand curve and the steeper the slope of the supply curve, the greater the price impact.

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

Impact of VRR Curve Shape

Table 23 shows what the 2019/2020 results would have been if the changes to the VRR curve shape that were introduced in the 2018/2019 RPM Base Residual Auction were not used in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. Figure 2 shows the RTO VRR curve for the 2019/2020 RPM Base Residual Auction as it would have been if the 2017/2018 definitions for the VRR curve points had been used. All binding constraints would have remained the same, except that the MAAC import limit would have been binding, and the BGE import limit would not have been binding.

The RTO clearing price for Capacity Performance Resources would have decreased to $94.89 per MW-day, and the clearing quantity would have decreased to 137,938.5 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $74.89 per MW-day, and the clearing quantity would have remained the same at 26,998.6 MW. The MAAC clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to 52,552.0 MW. The MAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have remained the same at $80.00 per MW-day, and the clearing quantity would have increased to 10,764.5 MW. The EMAAC clearing price for Capacity Performance Resources would have decreased to $113.83 per MW-day, and the clearing quantity would have decreased to 23,525.5 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $93.83 per MW-day, and the clearing quantity would have decreased to 6,764.4 MW. The Pepco clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to 5,354.3 MW. The Pepco clearing price and quantity cleared for Base Capacity Resources would have remained the same at $80.00 per MW-day and 48.3 MW. The Pepco clearing price and quantity cleared for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day and 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $190.00 per MW-day, and the clearing quantity would have decreased to 19,654.7 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $170.00 per MW-day, and the clearing quantity would have decreased to 3,126.5 MW. The BGE clearing price for Capacity Performance Resources would have decreased to $100.00 per MW-day, and the clearing quantity would have decreased to 2,128.6 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $80.00 per MW-day, and the clearing quantity would have remained the same at 599.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the 2017/2018 VRR curve shape were used in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,584,436,158, a decrease of $415,456,950, or 5.9 percent, compared to the actual results. From another perspective, the use of the revised VRR curve point definitions introduced in the 2018/2019 RPM Base Residual Auction resulted in a 6.3 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the prior VRR curve shape.

Impact of ComEd CETL

Table 24 shows the results if the 2017/2018 CETL value for ComEd had been used in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $104.00 per MW-day, and the clearing quantity would have decreased to 140,165.8 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $84.00 per MW-day, and the clearing quantity would have remained the same at 26,998.6. The EMAAC clearing price for Capacity Performance Resources would have remained the same at $119.77 per MW-day, and the clearing quantity would have remained the same at 24,003.6 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have remained the same at $99.77 per MW-day, and the clearing quantity would have remained the same at 6,765.5 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $104.00 per MW-day, and the clearing quantity would have increased to 5,880.4 MW. The Pepco clearing price for Base Capacity Resources would have increased to $84.00 per MW-day, and the clearing quantity would have decreased to 21.9 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have remained the same at 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $140.00 per MW-day, and the clearing quantity would have decreased to 18,436.4 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $120.00 per MW-day, and the clearing quantity would have decreased to 3,017.0 MW. The BGE clearing price for Capacity Performance Resources would have increased to $104.00 per MW-day, and the clearing quantity would have remained unchanged at 2,140.1 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $84.00 per MW-day, and the clearing quantity would have increased to 622.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the 2017/2018 CETL value for ComEd had been used in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,612,836,020, a decrease of $387,057,088, or 5.5 percent, compared to the actual results. From another perspective, the use of the 2019/2020 CETL value for ComEd resulted in a 5.9 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the 2017/2018 CETL value for ComEd.

Impact of the Forecast Peak Load

Table 25 shows the results if the forecast peak load had not been reduced by 2.6 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same.[101] All binding constraints would have remained the same, except that the BGE import limit would not have been binding, and the RTO Base Capacity Resource Constraint would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $109.77 per MW-day, and the clearing quantity would have increased to 143,978.6 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $109.77 per MW-day, and the clearing quantity would have increased to 27,778.5. The EMAAC clearing price for Capacity Performance Resources would have increased to $153.18 per MW-day, and the clearing quantity would have increased to 24,518.0 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $153.18 per MW-day, and the clearing quantity would have increased to 6,996.0 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $109.77 per MW-day, and the clearing quantity would have increased to 5,859.9 MW. The Pepco clearing price for Base Capacity Resources would have increased to $109.77 per MW-day, and the clearing quantity would have remained the same at 48.3 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have increased to $20.00 per MW-day, and the clearing quantity would have increased to 486.9 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $190.02 per MW-day, and the clearing quantity would have increased to 20,647.8. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $190.02 per MW-day, and the clearing quantity would have increased to 3,126.5 MW. The BGE clearing price for Capacity Performance Resources would have increased to $109.77 per MW-day, and the clearing quantity would have increased to 2,338.9 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $109.77 per MW-day, and the clearing quantity would have increased to 630.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If

101 The RTO load forecast for 2018 decreased 2.6 percent from 165,480 MW in the 2014 report to 161,129 MW in the 2015 report. See PJM. "2015 Load Forecast Report," <http://www.pjm.com/~/media/documents/reports/2015-load-forecast-report.ashx> (January 2015), p. 70. See also PJM. "2014 Load Forecast Report," <http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx> (January 2014), p. 70.

the forecast peak load had not been reduced by 2.6 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $8,101,386,204, an increase of $1,101,493,096, or 15.7 percent, compared to the actual results. From another perspective, a 2.6 percent reduction in the forecast peak load resulted in a 13.6 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction.

Net Revenue Offset Calculation

Table 26 shows the results if the lower of the price-based or cost-based energy offer were used in the net revenue offset calculation for the purpose of calculating RPM offer caps in the 2019/2020 RPM Base Residual Auction and everything else had remained the same.[102] All binding constraints would have remained the same, except that the MAAC import limit would have been binding. The RTO clearing price for Capacity Performance Resources would have decreased to $99.75 per MW-day, and the clearing quantity would have increased to 140,316.3 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $74.98 per MW-day, and the clearing quantity would have remained the same at 26,998.6. The MAAC clearing price for Capacity Performance Resources would have decreased to $99.77 per MW-day, and the clearing quantity would have decreased to 53,911.5 MW. The MAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $75.00 per MW-day, and the clearing quantity would have decreased to 10,399.9 MW. The EMAAC clearing price for Capacity Performance Resources would have remained the same at $119.77 per MW-day, and the clearing quantity would have increased to 24,074.6 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $95.00 per MW-day, and the clearing quantity would have decreased to 6,694.6 MW. The Pepco clearing price for Capacity Performance Resources would have decreased to $99.77 per MW-day, and the clearing quantity would have decreased to 5,355.0 MW. The Pepco clearing price for Base Capacity Resources would have decreased to $75.00 per MW-day, and the clearing quantity would have decreased to 21.9 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have remained the same at 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have increased to $204.15 per MW-day, and the clearing quantity would have increased to

102 Net revenue values for the 2019/2020 RPM BRA were calculated consistent with the FERC order effective at the time. *See FirstEnergy Solutions Corp. v. PJM Interconnection, L.L.C.*, 148 FERC ¶ 61,140 (2014). The MMU position was and is that the lower of price and cost-based offers should be used in the net revenue calculation because these offers best represent the actual short run marginal cost of the units.

19,856.9 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $179.38 per MW-day, and the clearing quantity would have decreased to 3,106.8 MW. The BGE clearing price for Capacity Performance Resources would have decreased $100.05 per MW-day, and the clearing quantity would have increased to 2,141.1 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $75.28 per MW-day, and the clearing quantity would decreased to 598.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If the lower of the price-based or cost-based energy offer were used in the net revenue offset calculation for the purpose of calculating RPM offer caps in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,956,448,094, a decrease of $43,445,014, or 0.6 percent, compared to the actual results. From another perspective, using cost-based energy offer in the net revenue offset calculation for the purpose of calculating RPM offer caps resulted in a 0.6 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been using the lower of the price-based or cost-based energy offer in the net revenue offset calculation.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 27 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from $35.00 per MW-day. Offers for DR and EE resources were 5.5 percent of the offers greater than $35.00 per MW-day. Offers for coal fired units, including non-coupled and coupled offers, made up 36.6 percent of the offers greater than $35.00 per MW-day.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2019/2020 BRA:[103] [104]

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

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

- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[105] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending 1500 and the hour ending 1800 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[106]

Effective for the 2014/2015 through the 2017/2018 Delivery Years, there are three types of Demand Resource products included in the RPM market design:[107] [108]

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

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

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

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

107 134 FERC ¶ 61,066 (2011).

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

- **Extended Summer DR.** A Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.

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

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:[109] [110]

- **Base Capacity Demand Resource.** A Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.

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

- **Capacity Performance Resource**

    - **Annual Demand Resource.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of

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[109] 151 FERC ¶ 61,208.

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

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

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

Effective with the 2020/2021 Delivery Year, the Capacity Performance product will be the only capacity product type.

Table 28 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2019/2020 RPM Base Residual Auction compared to the 2018/2019 RPM Base Residual Auction. Offers for DR increased from 11,675.5 MW in the 2018/2019 BRA to 11,818.0 MW in the 2019/2020 BRA, an increase of 142.5 MW or 1.2 percent. Offers for EE increased from 1,306.1 MW in the 2018/2019 BRA to 1,650.3 MW in the 2019/2020 BRA, an increase of 344.2 MW or 26.4 percent.

Impact of All DR and EE

Table 29 shows the results if there were no offers for DR or EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding, and the RTO Base Capacity Resource Constraint would not have been binding. The RTO clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to $130.96 per MW-day, and the clearing quantity would have decreased to 164,225.7 MW. The EMAAC clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to $184.34 per MW-day, and the clearing quantity would have decreased to 29,968.1 MW. The Pepco clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to $130.96 per MW-day, and the clearing quantity would have decreased to 5,931.3 MW. The ComEd clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to $210.00, and the clearing quantity would have decreased to 22,206.9 MW. The BGE clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to $130.96 per MW-day, and the clearing quantity would have increased to 3,224.7 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for DR or EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $9,099,465,731, an increase of $2,099,572,623, or 30.0 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 23.1 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

Impact of All EE

Table 30 shows the results if there were no offers for EE and the EE add back had been removed in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to 138,580.9 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have remained the same at $80.00 per MW-day, and the clearing quantity would have decreased to 26,834.1 MW. The EMAAC clearing price for Capacity Performance Resources would have increased to $119.83 per MW-day, and the clearing quantity would have decreased to 23,664.3 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $99.83 per MW-day, and the clearing quantity would have increased to 6,881.7 MW. The Pepco clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to 5,325.6 MW. The Pepco clearing price for Base Capacity Resources would have remained the same at $80.00 per MW-day, and the clearing quantity would have remained the same at 48.3 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have increased to $20.00 per MW-day, and the clearing quantity would have decreased to 465.6 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $202.72 per MW-day, and the clearing quantity would have decreased to 19,276.7 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $182.72 per MW-day, and the clearing quantity would have decreased to 2,969.9 MW. The BGE clearing price for Capacity Performance Resources would have decreased to $100.00 per MW-day, and the clearing quantity would have decreased to 2,040.2 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $80.00 per MW-day, and the clearing quantity would have decreased to 598.6 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for EE and the EE add back MW were set to zero in the 2019/2020 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,905,618,435, a decrease of $94,274,673, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of Energy Efficiency Resources resulted in a 1.4 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Energy Efficiency Resources.

Impact of Capacity Performance DR and EE

Table 31 shows the results if there had been no offers for CP DR or CP EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same.[111] All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $100.20 per MW-day, and the clearing quantity would have decreased to 139,430.5 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $79.99 per MW-day, and the clearing quantity would have decreased to 26,915.7. The EMAAC clearing price for Capacity Performance Resources would have remained the same at $119.77 per MW-day, and the clearing quantity would have increased to 24,014.3 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $99.56 per MW-day, and the clearing quantity would have decreased to 6,623.2 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $100.20 per MW-day, and the clearing quantity would have increased to 5,777.6 MW. The Pepco clearing price for Base Capacity Resources would have decreased to $79.99 per MW-day, and the clearing quantity would have decreased to 21.9 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing

111 The EE add back MW values for each LDA were adjusted to reflect the removal of CP EE offers for this scenario. As the product types of the EE Resources with accepted measurement and verification plans used in calculating the EE add back MW in the 2019/2020 RPM Base Residual Auction were not available, the EE add back MW values used for this scenario were calculated by multiplying the original EE add back values by the ratio of Base Capacity EE offers to total EE offers for each LDA.

quantity would have decreased to 468.8 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $190.02, and the clearing quantity would have decreased to 19,083.5 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $169.81 per MW-day, and the clearing quantity would have increased to 3,645.3 MW. The BGE clearing price for Capacity Performance Resources would have decreased to $100.20 per MW-day, and the clearing quantity would have decreased to 2,035.9 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $79.99 per MW-day, and the clearing quantity would have increased to 600.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for CP DR or CP EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,861,332,713, a decrease of $138,560,395, or 2.0 percent, compared to the actual results. From another perspective, the inclusion of Capacity Performance Demand Resources and Capacity Performance Energy Efficiency resources resulted in a 2.0 percent increase in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Capacity Performance Demand Resources or Capacity Performance Energy Efficiency resources.

Impact of Base Capacity DR and EE

Table 32 shows the results if there were no offers for Base Capacity DR or Base Capacity EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same.[112] All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $119.77 per MW-day, and the clearing quantity would have decreased to 138,749.7 MW. The RTO clearing price for Base Capacity Resources would have increased to $110.83 per MW-day, and the clearing quantity would have increased to 26,916.9 MW. The EMAAC clearing price for Capacity Performance Resources would have increased to $158.57 and the clearing quantity

[112] The EE add back MW values for each LDA were adjusted to reflect the removal of Base Capacity EE offers for this scenario. As the product types of the EE Resources with accepted measurement and verification plans used in calculating the EE add back MW in the 2019/2020 RPM Base Residual Auction were not available, the EE add back MW values used for this scenario were calculated by multiplying the original EE add back values by the ratio of Capacity Performance EE offers to total EE offers for each LDA.

would have increased to 21,307.3 MW. The EMAAC clearing price for Base Capacity Resources would have increased to $149.63 per MW-day, and the clearing quantity would have increased to 9,023.2 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $119.77 per MW-day, and the clearing quantity would have decreased to 5,600.1 MW. The Pepco clearing price for Base Capacity Resources would have increased to $110.83 per MW-day, and the clearing quantity would have decreased to 424.8 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $190.02 per MW-day, and the clearing quantity would have increased to 20,598.2 MW. The ComEd clearing price for Base Capacity Resources would have decreased to $181.08 per MW-day, and the clearing quantity would have decreased to 2,029.7 MW. The BGE clearing price for Capacity Performance Resources would have increased to $119.77 per MW-day, and the clearing quantity would have increased to 2,456.1 MW. The BGE clearing price for Base Capacity Resources would have increased to $110.83 per MW-day, and the clearing quantity would have decreased to 529.8 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there were no offers for Base Capacity DR or Base Capacity EE in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $8,206,198,971, an increase of $1,206,305,862, or 17.2 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Demand Resources and Base Capacity Energy Efficiency resources resulted in a 14.7 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Demand Resources or Base Capacity Energy Efficiency resources.

Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[113] [114] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain

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

114 See PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 51-52 & pp. 74-75.

firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Market.[115]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[116] [117] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[118] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[119]

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115 OATT, Schedule 1, Section 1.10.1A.

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

117 See PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 53-54.

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

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

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant Delivery Year due to the curtailment of firm transmission by third parties.[120] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant Delivery Year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external Generation Capacity Resource must obtain an exception to the CIL to be eligible to offer as a Capacity Performance Resource.[121]

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

Impact of Imports

Reduction by 25 Percent

Table 33 shows the results if import offers for external generation resources in the 2019/2020 RPM Base Residual Auction had been reduced by 25 percent and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $102.20 per MW-day, and the clearing quantity would have decreased to 140,229.3 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $82.43 per MW-day, and the clearing quantity would have stayed the same at 26,998.6 MW. The EMAAC clearing price for Capacity Performance Resources would have remained the same at $119.77 per MW-day, and the clearing quantity would have decreased to 24,003.6 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $100.00 per MW-day, and the clearing quantity would have increased to 6,765.6 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $102.20 per MW-day, and the clearing quantity would have increased to 5,854.1 MW. The Pepco clearing price for Base Capacity Resources would have increased to $82.43 per MW-day, and the clearing

[120] 147 FERC ¶ 61,060 (2014).

[121] 151 FERC ¶ 61,208 (2015).

quantity would have remained the same at 48.3 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have remained the same at 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $202.74 per MW-day, and the clearing quantity would have remained the same at 19,809.9 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $182.97 per MW-day, and the clearing quantity would have remained the same at 3,161.5 MW. The BGE clearing price for Capacity Performance Resources would have increased to $102.20 per MW-day, and the clearing quantity would have remained the same at 2,140.1 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $82.43 per MW-day, and the clearing quantity would have increased to 612.5 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If offers for external generation had been reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $7,089,724,034, an increase of $89,830,926, or 1.3 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 1.3 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 25 percent.[122]

Reduction by 75 Percent

Table 33 shows the results if offers for external generation resources in the 2019/2020 RPM Base Residual Auction were reduced by 75 percent and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $110.00 per MW-day, and the clearing quantity would have decreased to 139,952.8 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $90.00 per MW-day, and the clearing quantity would have stayed the same at 26,998.6 MW. The EMAAC clearing price for Capacity Performance Resources would have remained the same at $119.77 per MW-day, and the clearing quantity would have decreased to 23,840.7 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have remained the same at $99.77 per MW-day, and the clearing quantity would have increased to 6,928.6 MW. The Pepco clearing price for

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

Capacity Performance Resources would have increased to $110.00 per MW-day, and the clearing quantity would have increased to 5,859.9 MW. The Pepco clearing price for Base Capacity Resources would have increased to $90.00 per MW-day, and the clearing quantity would have remained the same at 48.3 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have remained the same at 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $202.75 per MW-day, and the clearing quantity would have remained the same at 19,809.9 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $182.75 per MW-day, and the clearing quantity would have remained the same at 3,161.5 MW. The BGE clearing price for Capacity Performance Resources would have increased to $110.00 per MW-day, and the clearing quantity would have increased to 2,141.2 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $90.00 per MW-day, and the clearing quantity would have increased to 630.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $7,399,063,952, an increase of $399,170,844, or 5.7 percent, compared to the actual results. From another perspective, the inclusion of all offers for external generation resources resulted in a 5.4 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if offers for external generation had been reduced by 75 percent.

Impact of Base Capacity Resources

Table 34 shows the results if there had been no offers for Base Capacity Resources and Base Capacity DR/EE Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same.[123] All import limit binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $163.13 per MW-day, and the clearing quantity would have decreased to 164,129.2 MW.

123 The EE add back MW values for each LDA were adjusted to reflect the removal of Base Capacity EE offers for this scenario. As the product types of the EE Resources with accepted measurement and verification plans used in calculating the EE add back MW in the 2019/2020 RPM Base Residual Auction were not available, the EE add back MW values used for this scenario were calculated by multiplying the original EE add back values by the ratio of Capacity Performance EE offers to total EE offers for each LDA.

The EMAAC clearing price for Capacity Performance Resources would have increased to $353.28 per MW-day, and the clearing quantity would have decreased to 29,183.9 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $163.13 per MW-day, and the clearing quantity would have decreased to 6,129.0 MW. The ComEd clearing price for Capacity Performance Resources would have increased to $212.00, and the clearing quantity would have decreased to 22,508.1 MW. The BGE clearing price for Capacity Performance Resources would have increased to $163.13 per MW-day, and the clearing quantity would have increased to 2,975.8 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for Base Capacity Resources and Base Capacity DR/EE Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $12,248,291,567, an increase of $5,248,398,459, or 75.0 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Resources and Base Capacity DR/EE Resources resulted in a 42.9 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Resources and Base Capacity DR/EE Resources.

Impact of All DR and Base Capacity Resources

Table 35 shows the results if there had been no offers for Base Capacity Resources, Base Capacity DR/EE Resources, or Capacity Performance DR/EE Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. All import limit binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $183.75 per MW-day, and the clearing quantity would have decreased to 162,446.2 MW. The EMAAC clearing price for Capacity Performance Resources would have increased to $385.89 per MW-day, and the clearing quantity would have decreased to 28,898.6 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $183.75 per MW-day, and the clearing quantity would have decreased to 6,026.5 MW. The ComEd clearing price for Capacity Performance Resources would have increased to $248.47, and the clearing quantity would have decreased to 22,002.8 MW. The BGE clearing price for Capacity Performance Resources would have increased to $183.75 per MW-day, and the clearing quantity would have increased to 2,800.1 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for Base Capacity Resources, Base Capacity DR/EE Resources, or Capacity Performance DR/EE Resources in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the

2019/2020 RPM Base Residual Auction would have been $13,595,336,649, an increase of $6,595,443,541, or 94.2 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Resources, Base Capacity DR/EE Resources, and Capacity Performance DR/EE Resources resulted in a 48.5 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Resources, Base Capacity DR/EE Resources, and Capacity Performance DR/EE Resources.

Impact of All DR, Base Capacity Resources, and Imports

Table 36 shows the results if there had been no offers for Base Capacity Resources, Base Capacity DR/EE Resources, or Capacity Performance DR/EE Resources and import offers for external generation resources had been reduced by 50 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same. All import limit binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have increased to $210.12 per MW-day, and the clearing quantity would have decreased to 161,511.0 MW. The EMAAC clearing price for Capacity Performance Resources would have increased to $385.89 per MW-day, and the clearing quantity would have decreased to 28,898.7 MW. The Pepco clearing price for Capacity Performance Resources would have increased to $210.12 per MW-day, and the clearing quantity would have decreased to 6,114.0 MW. The ComEd clearing price for Capacity Performance Resources would have increased to $248.47, and the clearing quantity would have decreased to 22,002.8 MW. The BGE clearing price for Capacity Performance Resources would have increased to $210.12 per MW-day, and the clearing quantity would have increased to 2,800.1 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If there had been no offers for Base Capacity Resources, Base Capacity DR/EE Resources, or Capacity Performance DR/EE Resources and import offers for external generation resources had been reduced by 50 percent in the 2019/2020 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $14,599,974,126, an increase of $7,600,081,018, or 108.6 percent, compared to the actual results. From another perspective, the inclusion of Base Capacity Resources, Base Capacity DR/EE Resources, and Capacity Performance DR/EE Resources and 50 percent of the offers for external generation resources resulted in a 52.1 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been without any Base Capacity Resources, Base Capacity DR/EE Resource, Capacity Performance DR/EE Resources and 50 percent of import offers for external generation resources.

Impact of Inconsistency Between EE Cleared MW and EE Add Back MW

Under the new EE add back MW rules, if the ratio of the EE add back MW to cleared EE MW in the BRA exceeds the predetermined threshold, then PJM adjusts the EE add back MW and reruns the auction clearing a second and final time. For the 2019/2020 RPM Base Residual Auction, the ratio in the initial solution of 1,891.4/1,515.1=1.248366444 did not exceed the threshold ratio of 1.380913275, so no adjustments were made to the EE add back MW. This meant that the demand curve was shifted by an amount greater than the quantity of cleared EE that shifted supply, so the clearing prices were affected by how the EE add back MW mechanism was implemented. Table 37 shows the results if adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2019/2020 RPM Base Residual Auction, and everything else had remained the same. All binding constraints would have remained the same, except that the BGE import limit would not have been binding. The RTO clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to 139,938.9 MW. The RTO clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have remained the same at $80.00 per MW-day, and the clearing quantity would have decreased to 26,963.4 MW. The EMAAC clearing price for Capacity Performance Resources would have increased to $119.83 per MW-day, and the clearing quantity would have decreased to 23,941.4 MW. The EMAAC clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have increased to $99.83 per MW-day, and the clearing quantity would have remained the same at 6,765.5 MW. The Pepco clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have increased to 5,530.1 MW. The Pepco clearing price for Base Capacity Resources would have remained the same at $80.00 per MW-day, and the clearing quantity would have remained the same at 48.3 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have decreased to 470.9 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to $202.71, and the clearing quantity would have remained the same at 19,809.9 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $182.71 per MW-day, and the clearing quantity would have remained that same at 3,161.5 MW. The BGE clearing price for Capacity Performance Resources would have decreased to $100.00 per MW-day, and the clearing quantity would have remained the same at 2,140.1 MW. The BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $80.00 per MW-day, and the clearing quantity would have remained that same at 599.4 MW.

Based on actual auction clearing prices and quantities and make whole MW, total RPM market revenues for the 2019/2020 RPM Base Residual Auction were $6,999,893,108. If adjustments to the EE add back MW had been made such that for each LDA the EE cleared MW were equal to the EE add back MW in the 2019/2020 RPM Base Residual Auction, and everything else had remained the same, total RPM market revenues for the 2019/2020 RPM Base Residual Auction would have been $6,983,867,441, a decrease of $16,025,667, or 0.2 percent, compared to the actual results. From another perspective, the inconsistency between the EE cleared MW and the adjustment to the demand with the EE add back MW, resulted in a 0.2 percent reduction in RPM revenues for the 2019/2020 RPM Base Residual Auction compared to what RPM revenues would have been if the EE add back MW were equal to the EE cleared MW for each LDA.

Tables and Figures for RTO Market

Table 12 RTO offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	195,203.0	184,479.8		
DR capacity	12,723.9	13,844.6		
EE capacity	1,600.4	1,741.1		
Total internal RTO capacity	209,527.3	200,065.5		
FRR	(15,385.3)	(14,408.4)		
Imports	5,310.4	4,762.3		
RPM capacity	199,452.4	190,419.4		
Exports	(1,318.2)	(1,288.6)		
FRR optional	(129.5)	(123.7)		
Excused Existing Generation Capacity Resources	(2,056.9)	(1,670.2)		
Unoffered Planned Generation Capacity Resources	(346.0)	(322.1)		
Unoffered DR and EE	(1,357.6)	(1,475.3)		
Available	194,244.2	185,539.5	100.0%	100.0%
Generation offered	181,866.4	172,071.2	93.6%	92.7%
DR offered	10,859.2	11,818.0	5.6%	6.4%
EE offered	1,517.4	1,650.3	0.8%	0.9%
Total offered	194,243.0	185,539.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	1.2	0.0	0.0%	0.0%
Cleared in RTO		164,051.7		88.4%
Cleared in LDAs		3,254.2		1.8%
Total cleared		167,305.9		90.2%
Make whole		23.6		0.0%
Uncleared generation		16,604.8		8.9%
Uncleared DR		1,470.0		0.8%
Uncleared EE		135.2		0.1%
Total uncleared		18,210.0		9.8%
Reliability requirement		157,092.4		
Total generation and DR cleared plus make whole		165,814.4		
Net excess/(deficit)		8,722.0		
Resource clearing price for Base Capacity DR/EE Resources ($ per MW-day)		$80.00		
Resource clearing price for Base Capacity Resources ($ per MW-day)		$80.00		
Resource clearing price for Capacity Performance Resources ($ per MW-day)		$100.00		
Preliminary zonal capacity price ($ per MW-day)		$96.77	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$96.77	A-B	

Table 13 RTO CP generation offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)
Internal RTO generation capacity	195,203.0	184,479.8
FRR	(14,795.2)	(13,766.3)
Imports	5,227.4	4,677.6
RPM generation capacity	185,635.2	175,391.1
Exports	(1,318.2)	(1,288.6)
FRR optional	(129.5)	(123.7)
Excused Existing Generation Capacity Resources - RPM must offer	(2,056.9)	(1,670.2)
Excused Existing Generation Capacity Resources - CP must offer	(1,250.0)	(1,042.8)
Unoffered Planned Generation Capacity Resources	(346.0)	(322.1)
Unoffered Intermittent Resources and Capacity Storage Resources	(4,009.8)	(3,902.4)
CP ineligible generation resources	0.0	0.0
Available CP generation capacity	176,524.8	167,041.3
CP generation offered	176,524.8	167,041.3
Unoffered CP Existing Generation Capacity Resources	0.0	0.0

Table 14 Capacity modifications (ICAP): 2019/2020 RPM Base Residual Auction[124]

	ICAP (MW)				
	RTO	EMAAC	Pepco	ComEd	BGE
Generation increases	6,807.8	243.0	952.0	53.3	0.0
Generation decreases	(2,927.1)	(1,279.4)	0.0	(7.2)	(51.3)
Capacity modifications net increase/(decrease)	3,880.7	(1,036.4)	952.0	46.1	(51.3)
DR increases	2,195.4	213.1	28.8	205.2	26.8
DR decreases	(2,496.2)	(278.9)	(174.0)	(423.4)	(127.8)
DR net increase/(decrease)	(300.8)	(65.8)	(145.2)	(218.2)	(101.0)
EE increases	834.6	162.5	66.1	215.3	17.9
EE decreases	(646.5)	(53.1)	(67.3)	(240.9)	(101.5)
EE modifications increase/(decrease)	188.1	109.4	(1.2)	(25.6)	(83.6)
Net internal capacity increase/(decrease)	3,768.0	(992.8)	805.6	(197.7)	(235.9)

124 Only cap mods that had a start date on or before June 1, 2019 and DR and EE plans for the 2019/2020 RPM Base Residual Auction are included.

Table 15 Capacity modifications (UCAP): 2019/2020 RPM Base Residual Auction

	UCAP (MW)				
	RTO	EMAAC	Pepco	ComEd	BGE
Generation increases	6,551.8	225.3	912.2	51.8	0.0
Generation decreases	(2,749.6)	(1,193.5)	0.0	(6.8)	(48.5)
Capacity modifications net increase/(decrease)	3,802.2	(968.2)	912.2	45.0	(48.5)
DR increases	2,378.2	230.8	31.2	222.3	29.0
DR decreases	(2,705.0)	(302.1)	(188.6)	(458.7)	(138.4)
DR net increase/(decrease)	(326.8)	(71.3)	(157.4)	(236.4)	(109.4)
EE increases	904.7	176.1	71.8	233.4	19.4
EE decreases	(700.4)	(57.8)	(72.9)	(260.9)	(109.9)
EE modifications increase/(decrease)	204.3	118.3	(1.1)	(27.5)	(90.5)
Net capacity/DR/EE modifications increase/(decrease)	3,679.7	(921.2)	753.7	(218.9)	(248.4)
EFORd effect	1,058.9	28.3	29.1	560.4	42.3
DR and EE effect	64.1	8.0	3.2	11.5	3.6
Net internal capacity increase/(decrease)	4,802.7	(884.9)	786.0	353.0	(202.5)

Table 16 Offered and cleared capacity by LDA, resource type, and offer/product type: 2019/2020 RPM Base Residual Auction

				Offered UCAP (MW)		Cleared UCAP (MW)	
LDA	Resource Type	Offer Type	Product Type(s)	Capacity Performance	Base Capacity	Capacity Performance	Base Capacity
RTO	GEN	Non-coupled	Capacity Performance	140,535.1		126,630.6	
RTO	GEN	Non-coupled	Base		5,023.0		4,976.1
RTO	GEN	Coupled	Capacity Performance and Base	26,506.2	26,221.3	12,004.9	11,831.2
RTO	DR	Non-coupled	Capacity Performance	498.3		441.3	
RTO	DR	Non-coupled	Base		6,656.9		5,772.4
RTO	DR	Coupled	Capacity Performance and Base	4,223.3	4,659.4	172.4	3,961.9
RTO	EE	Non-coupled	Capacity Performance	541.4		541.4	
RTO	EE	Non-coupled	Base		526.1		411.8
RTO	EE	Coupled	Capacity Performance and Base	582.1	582.3	516.7	45.2
EMAAC	GEN	Non-coupled	Capacity Performance	20,893.2		19,586.3	
EMAAC	GEN	Non-coupled	Base		1,910.6		1,880.7
EMAAC	GEN	Coupled	Capacity Performance and Base	8,432.5	8,147.1	4,249.7	3,255.3
EMAAC	DR	Non-coupled	Capacity Performance	9.0		9.0	
EMAAC	DR	Non-coupled	Base		1,235.7		1,127.0
EMAAC	DR	Coupled	Capacity Performance and Base	484.1	539.5	44.9	455.6
EMAAC	EE	Non-coupled	Capacity Performance	113.9		113.9	
EMAAC	EE	Non-coupled	Base		73.0		35.3
EMAAC	EE	Coupled	Capacity Performance and Base	18.2	18.5	0.0	11.6
Pepco	GEN	Non-coupled	Capacity Performance	4,290.0		3,916.2	
Pepco	GEN	Non-coupled	Base		16.9		16.9
Pepco	GEN	Coupled	Capacity Performance and Base	1,824.0	1,824.0	1,721.6	31.4
Pepco	DR	Non-coupled	Capacity Performance	0.0		0.0	
Pepco	DR	Non-coupled	Base		501.7		449.4
Pepco	DR	Coupled	Capacity Performance and Base	61.3	68.6	33.9	0.0
Pepco	EE	Non-coupled	Capacity Performance	53.9		53.9	
Pepco	EE	Non-coupled	Base		28.1		25.1
Pepco	EE	Coupled	Capacity Performance and Base	3.2	3.2	0.0	0.0
ComEd	GEN	Non-coupled	Capacity Performance	22,022.7		18,440.4	
ComEd	GEN	Non-coupled	Base		701.1		701.1
ComEd	GEN	Coupled	Capacity Performance and Base	1,347.7	1,347.7	832.5	515.2
ComEd	DR	Non-coupled	Capacity Performance	1.8		1.8	
ComEd	DR	Non-coupled	Base		891.4		884.4
ComEd	DR	Coupled	Capacity Performance and Base	813.6	898.5	2.0	869.2
ComEd	EE	Non-coupled	Capacity Performance	16.5		16.5	
ComEd	EE	Non-coupled	Base		189.5		189.5
ComEd	EE	Coupled	Capacity Performance and Base	518.9	518.9	516.7	2.1
BGE	GEN	Non-coupled	Capacity Performance	2,560.8		1,796.6	
BGE	GEN	Non-coupled	Base		317.6		303.6
BGE	GEN	Coupled	Capacity Performance and Base	392.3	392.3	239.3	42.9
BGE	DR	Non-coupled	Capacity Performance	6.0		3.3	
BGE	DR	Non-coupled	Base		599.7		149.0
BGE	DR	Coupled	Capacity Performance and Base	109.3	123.4	1.0	103.1
BGE	EE	Non-coupled	Capacity Performance	99.9		99.9	
BGE	EE	Non-coupled	Base		0.8		0.8
BGE	EE	Coupled	Capacity Performance and Base	0.0	0.0	0.0	0.0

Table 17 Weighted average sell offer prices by LDA, resource type, and offer/product type: 2019/2020 RPM Base Residual Auction

				Weighted-Average ($ per MW-day UCAP)	
LDA	Resource Type	Offer Type	Product Type(s)	Capacity Performance	Base
RTO	GEN	Non-coupled	Capacity Performance	$51.20	
RTO	GEN	Non-coupled	Base		$10.37
RTO	GEN	Coupled	Capacity Performance and Base	$76.07	$34.93
RTO	DR	Non-coupled	Capacity Performance	$21.20	
RTO	DR	Non-coupled	Base		$33.44
RTO	DR	Coupled	Capacity Performance and Base	$114.77	$43.16
RTO	EE	Non-coupled	Capacity Performance	$7.35	
RTO	EE	Non-coupled	Base		$38.10
RTO	EE	Coupled	Capacity Performance and Base	$14.34	$9.24
EMAAC	GEN	Non-coupled	Capacity Performance	$45.07	
EMAAC	GEN	Non-coupled	Base		$9.99
EMAAC	GEN	Coupled	Capacity Performance and Base	$85.04	$36.55
EMAAC	DR	Non-coupled	Capacity Performance	$0.00	
EMAAC	DR	Non-coupled	Base		$34.01
EMAAC	DR	Coupled	Capacity Performance and Base	$119.31	$51.04
EMAAC	EE	Non-coupled	Capacity Performance	$6.97	
EMAAC	EE	Non-coupled	Base		$85.12
EMAAC	EE	Coupled	Capacity Performance and Base	$131.15	$93.19
Pepco	GEN	Non-coupled	Capacity Performance	$75.80	
Pepco	GEN	Non-coupled	Base		$0.00
Pepco	GEN	Coupled	Capacity Performance and Base	$55.23	$49.57
Pepco	DR	Non-coupled	Capacity Performance		
Pepco	DR	Non-coupled	Base		$5.24
Pepco	DR	Coupled	Capacity Performance and Base	$124.71	$45.64
Pepco	EE	Non-coupled	Capacity Performance	$1.59	
Pepco	EE	Non-coupled	Base		$9.09
Pepco	EE	Coupled	Capacity Performance and Base	$134.84	$88.91
ComEd	GEN	Non-coupled	Capacity Performance	$85.91	
ComEd	GEN	Non-coupled	Base		$6.25
ComEd	GEN	Coupled	Capacity Performance and Base	$81.91	$19.66
ComEd	DR	Non-coupled	Capacity Performance	$75.00	
ComEd	DR	Non-coupled	Base		$31.92
ComEd	DR	Coupled	Capacity Performance and Base	$116.97	$49.33
ComEd	EE	Non-coupled	Capacity Performance	$11.86	
ComEd	EE	Non-coupled	Base		$2.55
ComEd	EE	Coupled	Capacity Performance and Base	$0.55	$0.37
BGE	GEN	Non-coupled	Capacity Performance	$96.64	
BGE	GEN	Non-coupled	Base		$36.36
BGE	GEN	Coupled	Capacity Performance and Base	$241.63	$77.94
BGE	DR	Non-coupled	Capacity Performance	$87.08	
BGE	DR	Non-coupled	Base		$94.89
BGE	DR	Coupled	Capacity Performance and Base	$121.83	$44.79
BGE	EE	Non-coupled	Capacity Performance	$0.14	
BGE	EE	Non-coupled	Base		$13.73
BGE	EE	Coupled	Capacity Performance and Base		

Table 18 Offered capacity by resource type, offer/product type and price range as percent of net CONE times B: 2019/2020 RPM Base Residual Auction[125]

			Offered UCAP (MW)					
			Capacity Performance			Base Capacity		
Resource Type	Offer Type	Product Type(s)	0 Percent	0 to 50 Percent	50 to > 100 Percent	0 Percent	0 to 50 Percent	50 to > 100 Percent
GEN	Non-coupled	Capacity Performance	13,492.1	107,369.2	19,673.8			
GEN	Non-coupled	Base				3,844.7	1,131.4	46.9
GEN	Coupled	Capacity Performance and Base	0.0	20,974.6	5,531.6	16,409.1	7,805.5	2,006.7
DR	Non-coupled	Capacity Performance	325.8	115.5	57.0			
DR	Non-coupled	Base				872.8	4,989.5	794.6
DR	Coupled	Capacity Performance and Base	0.0	2,760.2	1,463.1	0.0	4,303.4	356.0
EE	Non-coupled	Capacity Performance	227.8	313.6	0.0			
EE	Non-coupled	Base				232.4	232.6	61.1
EE	Coupled	Capacity Performance and Base	0.0	525.6	56.5	516.8	56.8	8.7

Table 19 Cleared MW by zone and resource type/fuel source: 2019/2020 RPM Base Residual Auction[126]

	Cleared UCAP (MW)										
Zone	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	Total
AECO	145.7	14.1	446.0	1,002.5	0.0	0.0	24.4	15.4	0.0	0.0	1,648.1
AEP	1,416.1	72.0	6,028.0	9,027.4	100.2	0.0	0.0	0.0	40.4	225.8	16,909.9
AP	926.0	26.8	4,732.5	3,117.5	129.8	0.0	0.0	12.9	0.0	121.1	9,066.6
ATSI	897.6	41.0	4,080.7	3,120.1	0.0	1,761.2	390.5	0.0	0.0	0.0	10,291.1
BGE	256.4	100.7	1,700.1	417.2	0.0	1,683.4	209.1	0.0	56.0	0.0	4,422.9
ComEd	1,757.4	724.8	4,658.9	8,230.3	0.0	6,930.8	221.5	3.4	0.0	444.3	22,971.4
DAY	219.8	24.5	2,296.3	1,304.9	0.0	0.0	50.8	0.5	0.0	0.0	3,896.8
DEOK	236.7	24.4	2,074.4	506.3	105.0	0.0	24.8	0.0	0.0	0.0	2,971.6
DLCO	247.2	14.1	0.0	191.1	0.0	1,525.9	0.0	0.0	0.0	0.0	1,978.3
Dominion	729.7	152.0	4,605.4	13,059.7	3,299.5	3,498.1	1,657.3	142.8	216.4	27.0	27,387.9
DPL	371.6	22.4	353.0	3,698.6	0.0	0.0	510.3	44.3	0.0	0.0	5,000.2
EKPC	140.4	8.6	1,622.0	1,155.8	114.6	0.0	0.0	0.0	0.0	0.0	3,041.4
External	0.0	0.0	2,828.6	326.9	623.0	97.4	0.0	0.0	0.0	0.0	3,875.9
JCPL	200.8	21.2	0.0	2,835.0	411.6	0.0	152.5	54.7	9.0	0.0	3,684.8
Met-Ed	321.7	18.2	111.4	1,952.5	16.2	0.0	295.6	0.0	69.3	0.0	2,784.9
PECO	527.4	41.1	9.0	3,943.0	1,624.1	4,596.9	792.5	1.0	89.8	0.0	11,624.8
PENELEC	339.4	17.3	4,888.5	1,169.0	570.3	0.0	60.1	0.0	40.4	126.3	7,211.3
Pepco	483.3	79.0	1,977.2	4,151.1	0.0	0.0	236.2	0.0	44.9	0.0	6,971.7
PPL	739.8	50.9	1,162.2	7,552.9	709.5	2,461.7	38.9	5.7	8.8	24.5	12,754.9
PSEG	380.7	49.3	0.0	4,820.6	3.3	3,333.4	0.0	54.3	146.8	0.0	8,788.4
RECO	10.3	12.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0
Total	10,348.0	1,515.1	43,574.2	71,582.4	7,707.1	25,888.8	4,664.5	335.0	721.8	969.0	167,305.9

125 Data aggregated based on PJM confidentiality rules.

126 Resources that operate at or above 500 kV may be physically located in a zonal LDA but are modeled in the parent LDA. For example, 3,333.4 MW of the 8,788.4 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

Table 20 Uncleared generation offers by technology type and age: 2019/2020 RPM Base Residual Auction[127] [128]

	Uncleared UCAP (MW)		
Technology Type	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	Total
Coal Fired	1,101.6	6,568.0	7,669.6
Combined cycle	1,777.4	0.0	1,777.4
Combustion turbine	917.0	650.6	1,567.6
Oil or gas steam	29.9	886.5	916.4
Other	2,437.7	2,236.1	4,673.8
Total	6,263.6	10,341.2	16,604.8

Table 21 Uncleared generation resources in multiple auctions[129] [130]

	2019/2020		2018/2019 Results for Same Set of Resources		2017/2018 Results for Same Set of Resources	
Technology	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources
Coal Fired	7,669.6	79	3,511.6	63	2,309.1	37
Combined cycle	1,777.4	39	356.1	16	338.2	6
Combustion turbine	1,567.6	108	864.9	66	704.5	14
Other	5,590.2	51	3,157.0	22	136.0	6
Total	16,604.8	277	7,889.6	167	3,487.8	63

127 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2019/2020 BRA, waste coal resources are included in the coal fired category.

128 Data aggregated based on PJM confidentiality rules.

129 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2019/2020 BRA, waste coal resources are included in the coal fired category.

130 Data aggregated based on PJM confidentiality rules.

Table 22 PJM LDA CETL and CETO values: 2018/2019 and 2019/2020 RPM Base Residual Auctions

	2018/2019			2019/2020			Change			
			CETL to CETO			CETL to CETO	CETO		CETL	
LDA	CETO	CETL	Ratio	CETO	CETL	Ratio	MW	Percent	MW	Percent
MAAC	(1,900.0)	7,883.0	(415%)	(6,930.0)	7,385.0	(107%)	(5,030.0)	265%	(498.0)	(6%)
EMAAC	2,850.0	8,375.0	294%	1,580.0	8,856.0	561%	(1,270.0)	(45%)	481.0	6%
SWMAAC	5,160.0	9,888.0	192%	3,920.0	9,400.0	240%	(1,240.0)	(24%)	(488.0)	(5%)
PSEG	5,800.0	7,926.0	137%	5,590.0	7,856.0	141%	(210.0)	(4%)	(70.0)	(1%)
PSEG North	2,350.0	3,761.0	160%	2,280.0	3,827.0	168%	(70.0)	(3%)	66.0	2%
DPL South	1,360.0	1,702.0	125%	1,230.0	1,898.0	154%	(130.0)	(10%)	196.0	12%
Pepco	3,470.0	7,045.0	203%	2,870.0	6,985.0	243%	(600.0)	(17%)	(60.0)	(1%)
ATSI	4,520.0	9,240.0	204%	4,490.0	9,212.0	205%	(30.0)	(1%)	(28.0)	(0%)
ATSI Cleveland	3,340.0	4,557.0	136%	3,390.0	5,501.0	162%	50.0	1%	944.0	21%
ComEd	860.0	5,227.0	608%	610.0	5,160.0	846%	(250.0)	(29%)	(67.0)	(1%)
BGE	4,550.0	6,527.0	143%	4,060.0	6,234.7	154%	(490.0)	(11%)	(292.3)	(4%)
PPL	(500.0)	4,538.0	(908%)	(170.0)	6,168.0	(3,628%)	330.0	(66%)	1,630.0	36%

Table 23 Impact of VRR curve shape: 2019/2020 RPM Base Residual Auction (Scenario 1)

		Actual Auction Results		VRR Curve Shape	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$74.89	10,111.0
	Base Capacity	$80.00	16,807.3	$74.89	16,887.6
	Capacity Performance	$100.00	140,307.3	$94.89	137,938.5
RTO Total			167,305.9		164,937.1
MAAC	Base Capacity DR/EE	$80.00	3,699.0	$80.00	3,697.2
	Base Capacity	$80.00	6,907.5	$80.00	7,067.3
	Capacity Performance	$100.00	54,308.5	$100.00	52,552.0
MAAC Total			64,915.0		63,316.5
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$93.83	1,628.4
	Base Capacity	$99.77	5,136.0	$93.83	5,136.0
	Capacity Performance	$119.77	24,003.8	$113.83	23,525.5
EMAAC Total			30,769.3		30,289.9
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	474.5
	Base Capacity	$80.00	48.3	$80.00	48.3
	Capacity Performance	$100.00	5,725.6	$100.00	5,354.3
Pepco Total			6,248.4		5,877.1
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$170.00	1,910.2
	Base Capacity	$182.77	1,216.3	$170.00	1,216.3
	Capacity Performance	$202.77	19,809.9	$190.00	19,654.7
ComEd Total			22,971.4		22,781.2
BGE	Base Capacity DR/EE	$80.30	252.9	$80.00	252.9
	Base Capacity	$80.30	346.5	$80.00	346.5
	Capacity Performance	$100.30	2,140.1	$100.00	2,128.6
BGE Total			2,739.5		2,728.0

Table 24 Impact of ComEd CETL change: 2019/2020 RPM Base Residual Auction (Scenario 2)

		Actual Auction Results		ComEd CETL	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$84.00	10,144.0
	Base Capacity	$80.00	16,807.3	$84.00	16,854.6
	Capacity Performance	$100.00	140,307.3	$104.00	140,165.8
RTO Total			167,305.9		167,164.4
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$99.77	1,629.5
	Base Capacity	$99.77	5,136.0	$99.77	5,136.0
	Capacity Performance	$119.77	24,003.8	$119.77	24,003.6
EMAAC Total			30,769.3		30,769.1
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	474.5
	Base Capacity	$80.00	48.3	$84.00	21.9
	Capacity Performance	$100.00	5,725.6	$104.00	5,880.4
Pepco Total			6,248.4		6,376.8
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$120.00	1,833.1
	Base Capacity	$182.77	1,216.3	$120.00	1,183.9
	Capacity Performance	$202.77	19,809.9	$140.00	18,436.4
ComEd Total			22,971.4		21,453.4
BGE	Base Capacity DR/EE	$80.30	252.9	$84.00	276.0
	Base Capacity	$80.30	346.5	$84.00	346.5
	Capacity Performance	$100.30	2,140.1	$104.00	2,140.1
BGE Total			2,739.5		2,762.6

Table 25 Impact of the forecast peak load: 2019/2020 RPM Base Residual Auction (Scenario 3)

		Actual Auction Results		Forecast Peak Load Not Reduced by 2.6 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$109.77	10,534.2
	Base Capacity	$80.00	16,807.3	$109.77	17,244.3
	Capacity Performance	$100.00	140,307.3	$109.77	143,978.6
RTO Total			167,305.9		171,757.1
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$153.18	1,699.7
	Base Capacity	$99.77	5,136.0	$153.18	5,296.3
	Capacity Performance	$119.77	24,003.8	$153.18	24,518.0
EMAAC Total			30,769.3		31,514.0
Pepco	Base Capacity DR/EE	$0.01	474.5	$20.00	486.9
	Base Capacity	$80.00	48.3	$109.77	48.3
	Capacity Performance	$100.00	5,725.6	$109.77	5,859.9
Pepco Total			6,248.4		6,395.1
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$190.02	1,910.2
	Base Capacity	$182.77	1,216.3	$190.02	1,216.3
	Capacity Performance	$202.77	19,809.9	$190.02	20,647.8
ComEd Total			22,971.4		23,774.3
BGE	Base Capacity DR/EE	$80.30	252.9	$109.77	283.9
	Base Capacity	$80.30	346.5	$109.77	346.5
	Capacity Performance	$100.30	2,140.1	$109.77	2,338.9
BGE Total			2,739.5		2,969.3

Table 26 Impact of net revenue offset calculation: 2019/2020 RPM Base Residual Auction (Scenario 4)

		Actual Auction Results		Net Revenue Offset Calculation	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$74.98	10,081.1
	Base Capacity	$80.00	16,807.3	$74.98	16,917.5
	Capacity Performance	$100.00	140,307.3	$99.75	140,316.3
RTO Total			167,305.9		167,314.9
MAAC	Base Capacity DR/EE	$80.00	3,699.0	$75.00	3,655.8
	Base Capacity	$80.00	6,907.5	$75.00	6,744.1
	Capacity Performance	$100.00	54,308.5	$99.77	53,911.5
MAAC Total			64,915.0		64,311.4
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$95.00	1,620.6
	Base Capacity	$99.77	5,136.0	$95.00	5,074.0
	Capacity Performance	$119.77	24,003.8	$119.77	24,074.6
EMAAC Total			30,769.3		30,769.2
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	474.5
	Base Capacity	$80.00	48.3	$75.00	21.9
	Capacity Performance	$100.00	5,725.6	$99.77	5,355.0
Pepco Total			6,248.4		5,851.4
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$179.38	1,935.4
	Base Capacity	$182.77	1,216.3	$179.38	1,171.4
	Capacity Performance	$202.77	19,809.9	$204.15	19,856.9
ComEd Total			22,971.4		22,963.7
BGE	Base Capacity DR/EE	$80.30	252.9	$75.28	251.9
	Base Capacity	$80.30	346.5	$75.28	346.5
	Capacity Performance	$100.30	2,140.1	$100.05	2,141.1
BGE Total			2,739.5		2,739.5

Table 27 Offers greater than $35.00 per MW-day in total RTO supply curve: 2019/2020 RPM Base Residual Auction[131] [132] [133]

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	29,108.3	36.6%
Combustion turbine	14,836.6	18.7%
Combined cycle	14,339.4	18.0%
Nuclear	10,516.5	13.2%
Oil or gas steam	4,805.6	6.0%
Demand Resource	4,129.4	5.2%
Hydro	1,229.4	1.5%
Energy Efficiency Resource	257.3	0.3%
Other generation	218.5	0.3%
Wind	58.4	0.1%
Total	79,499.4	100.0%

131 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in the offered capacity values reported.

132 Effective for the 2017/2018 and subsequent Delivery Years, the ACR technology classes of waste coal small and large were eliminated and combined with subcritical and supercritical coal to form the Coal Fired ACR technology class. Waste coal resources were included in the other category in versions of this table prior to the 2017/2018 BRA. For the 2019/2020 BRA, waste coal resources are included in the coal fired category.

133 Data aggregated based on PJM confidentiality rules.

Table 28 DR and EE statistics by LDA: 2018/2019 and 2019/2020 RPM Base Residual Auctions[134]

		2018/2019 BRA			2019/2020 BRA			Change					
								Offered ICAP		Offered UCAP		Cleared UCAP	
LDA	Resource Type	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	MW	Percent	MW	Percent	MW	Percent
RTO	DR	10,772.8	11,675.5	11,084.4	10,859.2	11,818.0	10,348.0	86.4	0.8%	142.5	1.2%	(736.4)	(6.6%)
RTO	EE	1,205.5	1,306.1	1,246.5	1,517.4	1,650.3	1,515.1	311.9	25.9%	344.2	26.4%	268.6	21.5%
MAAC	DR	4,413.3	4,783.5	4,286.0	4,293.6	4,673.2	3,777.1	(119.7)	(2.7%)	(110.3)	(2.3%)	(508.9)	(11.9%)
MAAC	EE	275.2	298.4	258.6	455.4	495.0	426.9	180.2	65.5%	196.6	65.9%	168.3	65.1%
EMAAC	DR	1,569.2	1,701.4	1,674.6	1,640.9	1,786.1	1,636.5	71.7	4.6%	84.7	5.0%	(38.1)	(2.3%)
EMAAC	EE	50.6	55.0	54.3	189.3	205.5	160.8	138.7	274.1%	150.5	273.6%	106.5	196.1%
SWMAAC	DR	1,366.5	1,481.0	1,183.1	1,194.1	1,299.7	739.7	(172.4)	(12.6%)	(181.3)	(12.2%)	(443.4)	(37.5%)
SWMAAC	EE	186.0	201.4	162.3	171.0	185.9	179.7	(15.0)	(8.1%)	(15.5)	(7.7%)	17.4	10.7%
DPL South	DR	82.2	89.2	86.8	94.2	102.5	91.3	12.0	14.6%	13.3	14.9%	4.5	5.2%
DPL South	EE	0.0	0.0	0.0	0.9	1.0	1.0	0.9	NA	1.0	NA	1.0	NA
PSEG	DR	356.4	386.6	382.2	392.8	427.8	380.7	36.4	10.2%	41.2	10.7%	(1.5)	(0.4%)
PSEG	EE	13.2	14.5	14.1	54.7	59.6	49.3	41.5	314.4%	45.1	311.0%	35.2	249.6%
PSEG North	DR	122.8	133.4	132.6	171.6	187.2	176.5	48.8	39.7%	53.8	40.3%	43.9	33.1%
PSEG North	EE	1.8	2.0	1.8	7.8	8.4	8.4	6.0	333.3%	6.4	320.0%	6.6	366.7%
Pepco	DR	615.4	667.1	523.1	524.2	570.4	483.3	(91.2)	(14.8%)	(96.7)	(14.5%)	(39.8)	(7.6%)
Pepco	EE	62.2	67.3	66.4	78.2	85.2	79.0	16.0	25.7%	17.9	26.6%	12.6	19.0%
ATSI	DR	822.5	891.9	877.0	898.7	978.0	897.6	76.2	9.3%	86.1	9.7%	20.6	2.3%
ATSI	EE	35.9	38.8	38.8	48.5	52.8	41.0	12.6	35.1%	14.0	36.1%	2.2	5.7%
ATSI Cleveland	DR	250.9	272.3	267.6	281.1	305.9	289.9	30.2	12.0%	33.6	12.3%	22.3	8.3%
ATSI Cleveland	EE	5.2	5.6	5.6	0.2	0.2	0.2	(5.0)	(96.2%)	(5.4)	(96.4%)	(5.4)	(96.4%)
ComEd	DR	1,754.6	1,901.2	1,876.7	1,646.7	1,792.0	1,757.4	(107.9)	(6.1%)	(109.2)	(5.7%)	(119.3)	(6.4%)
ComEd	EE	687.2	744.4	744.4	666.2	725.1	724.8	(21.0)	(3.1%)	(19.3)	(2.6%)	(19.6)	(2.6%)
BGE	DR	751.1	813.9	660.0	669.9	729.3	256.4	(81.2)	(10.8%)	(84.6)	(10.4%)	(403.6)	(61.2%)
BGE	EE	123.8	134.1	95.9	92.8	100.7	100.7	(31.0)	(25.0%)	(33.4)	(24.9%)	4.8	5.0%
PPL	DR	806.2	873.6	716.2	749.3	815.6	739.8	(56.9)	(7.1%)	(58.0)	(6.6%)	23.6	3.3%
PPL	EE	23.1	25.0	25.0	52.2	56.8	50.9	29.1	126.0%	31.8	127.2%	25.9	103.6%

134 The maximum capacity within a coupled segment group was included in the offered capacity values reported.

Table 29 Impact of demand side products: 2019/2020 RPM Base Residual Auction (Scenario 5)

		Actual Auction Results		No Offers for DR or EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3		
	Base Capacity	$80.00	16,807.3	$130.96	26,834.1
	Capacity Performance	$100.00	140,307.3	$130.96	137,391.6
RTO Total			167,305.9		164,225.7
EMAAC	Base Capacity DR/EE	$99.77	1,629.5		
	Base Capacity	$99.77	5,136.0	$184.34	8,684.9
	Capacity Performance	$119.77	24,003.8	$184.34	21,283.2
EMAAC Total			30,769.3		29,968.1
Pepco	Base Capacity DR/EE	$0.01	474.5		
	Base Capacity	$80.00	48.3	$130.96	424.8
	Capacity Performance	$100.00	5,725.6	$130.96	5,506.5
Pepco Total			6,248.4		5,931.3
ComEd	Base Capacity DR/EE	$182.77	1,945.2		
	Base Capacity	$182.77	1,216.3	$210.00	1,992.4
	Capacity Performance	$202.77	19,809.9	$210.00	20,214.5
ComEd Total			22,971.4		22,206.9
BGE	Base Capacity DR/EE	$80.30	252.9		
	Base Capacity	$80.30	346.5	$130.96	636.4
	Capacity Performance	$100.30	2,140.1	$130.96	2,588.3
BGE Total			2,739.5		3,224.7

Table 30 Impact of EE Resources: 2019/2020 RPM Base Residual Auction (Scenario 6)

		Actual Auction Results		No Offers for EE and EE Add Back Removed	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$80.00	9,750.5
	Base Capacity	$80.00	16,807.3	$80.00	17,083.6
	Capacity Performance	$100.00	140,307.3	$100.00	138,580.9
RTO Total			167,305.9		165,415.0
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$99.83	1,582.6
	Base Capacity	$99.77	5,136.0	$99.83	5,299.1
	Capacity Performance	$119.77	24,003.8	$119.83	23,664.3
EMAAC Total			30,769.3		30,546.0
Pepco	Base Capacity DR/EE	$0.01	474.5	$20.00	465.6
	Base Capacity	$80.00	48.3	$80.00	48.3
	Capacity Performance	$100.00	5,725.6	$100.00	5,325.6
Pepco Total			6,248.4		5,839.5
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$182.72	1,753.6
	Base Capacity	$182.77	1,216.3	$182.72	1,216.3
	Capacity Performance	$202.77	19,809.9	$202.72	19,276.7
ComEd Total			22,971.4		22,246.6
BGE	Base Capacity DR/EE	$80.30	252.9	$80.00	252.1
	Base Capacity	$80.30	346.5	$80.00	346.5
	Capacity Performance	$100.30	2,140.1	$100.00	2,040.2
BGE Total			2,739.5		2,638.8

Table 31 Impact of Capacity Performance demand side products: 2019/2020 RPM Base Residual Auction (Scenario 9)

		Actual Auction Results		No Offers for CP DR or EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$79.99	10,716.8
	Base Capacity	$80.00	16,807.3	$79.99	16,198.9
	Capacity Performance	$100.00	140,307.3	$100.20	139,430.5
RTO Total			167,305.9		166,346.2
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$99.56	1,672.2
	Base Capacity	$99.77	5,136.0	$99.56	4,951.0
	Capacity Performance	$119.77	24,003.8	$119.77	24,014.3
EMAAC Total			30,769.3		30,637.5
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	468.8
	Base Capacity	$80.00	48.3	$79.99	21.9
	Capacity Performance	$100.00	5,725.6	$100.20	5,777.6
Pepco Total			6,248.4		6,268.3
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$169.81	2,429.0
	Base Capacity	$182.77	1,216.3	$169.81	1,216.3
	Capacity Performance	$202.77	19,809.9	$190.02	19,083.5
ComEd Total			22,971.4		22,728.8
BGE	Base Capacity DR/EE	$80.30	252.9	$79.99	253.9
	Base Capacity	$80.30	346.5	$79.99	346.5
	Capacity Performance	$100.30	2,140.1	$100.20	2,035.9
BGE Total			2,739.5		2,636.3

Table 32 Impact of Base Capacity demand side products: 2019/2020 RPM Base Residual Auction (Scenario 8)

		Actual Auction Results		No Offers for Base DR or EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3		
	Base Capacity	$80.00	16,807.3	$110.83	26,916.9
	Capacity Performance	$100.00	140,307.3	$119.77	138,749.7
RTO Total			167,305.9		165,666.6
EMAAC	Base Capacity DR/EE	$99.77	1,629.5		
	Base Capacity	$99.77	5,136.0	$149.63	9,023.2
	Capacity Performance	$119.77	24,003.8	$158.57	21,307.3
EMAAC Total			30,769.3		30,330.5
Pepco	Base Capacity DR/EE	$0.01	474.5		
	Base Capacity	$80.00	48.3	$110.83	424.8
	Capacity Performance	$100.00	5,725.6	$119.77	5,600.1
Pepco Total			6,248.4		6,024.9
ComEd	Base Capacity DR/EE	$182.77	1,945.2		
	Base Capacity	$182.77	1,216.3	$181.08	2,029.7
	Capacity Performance	$202.77	19,809.9	$190.02	20,598.2
ComEd Total			22,971.4		22,627.9
BGE	Base Capacity DR/EE	$80.30	252.9		
	Base Capacity	$80.30	346.5	$110.83	529.8
	Capacity Performance	$100.30	2,140.1	$119.77	2,456.1
BGE Total			2,739.5		2,985.9

Table 33 Impact of capacity imports: 2019/2020 RPM Base Residual Auction (Scenarios 10, 11, 12)

		Actual Auction Results		Reduce Imports by 25 Percent		Reduce Imports by 50 Percent		Reduce Imports by 75 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$82.43	10,221.7	$86.88	10,282.3	$90.00	10,507.6
	Base Capacity	$80.00	16,807.3	$82.43	16,776.9	$86.88	16,716.3	$90.00	16,491.0
	Capacity Performance	$100.00	140,307.3	$102.20	140,229.3	$107.06	140,056.8	$110.00	139,952.8
RTO Total			167,305.9		167,227.9		167,055.4		166,951.4
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$100.00	1,629.6	$99.59	1,629.5	$99.77	1,629.5
	Base Capacity	$99.77	5,136.0	$100.00	5,136.0	$99.59	5,296.3	$99.77	5,299.1
	Capacity Performance	$119.77	24,003.8	$119.77	24,003.6	$119.77	23,843.3	$119.77	23,840.7
EMAAC Total			30,769.3		30,769.2		30,769.1		30,769.3
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	474.5	$0.01	474.5	$0.01	474.5
	Base Capacity	$80.00	48.3	$82.43	48.3	$86.88	48.3	$90.00	48.3
	Capacity Performance	$100.00	5,725.6	$102.20	5,854.1	$107.06	5,854.6	$110.00	5,859.9
Pepco Total			6,248.4		6,376.9		6,377.4		6,382.7
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$182.97	1,945.2	$182.57	1,945.2	$182.75	1,945.2
	Base Capacity	$182.77	1,216.3	$182.97	1,216.3	$182.57	1,216.3	$182.75	1,216.3
	Capacity Performance	$202.77	19,809.9	$202.74	19,809.9	$202.75	19,809.9	$202.75	19,809.9
ComEd Total			22,971.4		22,971.4		22,971.4		22,971.4
BGE	Base Capacity DR/EE	$80.30	252.9	$82.43	266.0	$86.88	277.0	$90.00	283.9
	Base Capacity	$80.30	346.5	$82.43	346.5	$86.88	346.5	$90.00	346.5
	Capacity Performance	$100.30	2,140.1	$102.20	2,140.1	$107.06	2,140.1	$110.00	2,141.2
BGE Total			2,739.5		2,752.6		2,763.6		2,771.6

Table 34 Impact of Base Capacity Resources: 2019/2020 RPM Base Residual Auction (Scenario 13)

		Actual Auction Results		CP Resources Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3		
	Base Capacity	$80.00	16,807.3		
	Capacity Performance	$100.00	140,307.3	$163.13	164,129.2
RTO Total			167,305.9		164,129.2
EMAAC	Base Capacity DR/EE	$99.77	1,629.5		
	Base Capacity	$99.77	5,136.0		
	Capacity Performance	$119.77	24,003.8	$353.28	29,183.9
EMAAC Total			30,769.3		29,183.9
Pepco	Base Capacity DR/EE	$0.01	474.5		
	Base Capacity	$80.00	48.3		
	Capacity Performance	$100.00	5,725.6	$163.13	6,129.0
Pepco Total			6,248.4		6,129.0
ComEd	Base Capacity DR/EE	$182.77	1,945.2		
	Base Capacity	$182.77	1,216.3		
	Capacity Performance	$202.77	19,809.9	$212.00	22,508.1
ComEd Total			22,971.4		22,508.1
BGE	Base Capacity DR/EE	$80.30	252.9		
	Base Capacity	$80.30	346.5		
	Capacity Performance	$100.30	2,140.1	$163.13	2,975.8
BGE Total			2,739.5		2,975.8

Table 35 Impact of all DR and Base Capacity Resources: 2019/2020 RPM Base Residual Auction (Scenario 14)

		Actual Auction Results		CP Gen Resources Only	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3		
	Base Capacity	$80.00	16,807.3		
	Capacity Performance	$100.00	140,307.3	$183.75	162,446.2
RTO Total			167,305.9		162,446.2
EMAAC	Base Capacity DR/EE	$99.77	1,629.5		
	Base Capacity	$99.77	5,136.0		
	Capacity Performance	$119.77	24,003.8	$385.89	28,898.6
EMAAC Total			30,769.3		28,898.6
Pepco	Base Capacity DR/EE	$0.01	474.5		
	Base Capacity	$80.00	48.3		
	Capacity Performance	$100.00	5,725.6	$183.75	6,026.5
Pepco Total			6,248.4		6,026.5
ComEd	Base Capacity DR/EE	$182.77	1,945.2		
	Base Capacity	$182.77	1,216.3		
	Capacity Performance	$202.77	19,809.9	$248.47	22,002.8
ComEd Total			22,971.4		22,002.8
BGE	Base Capacity DR/EE	$80.30	252.9		
	Base Capacity	$80.30	346.5		
	Capacity Performance	$100.30	2,140.1	$183.75	2,800.1
BGE Total			2,739.5		2,800.1

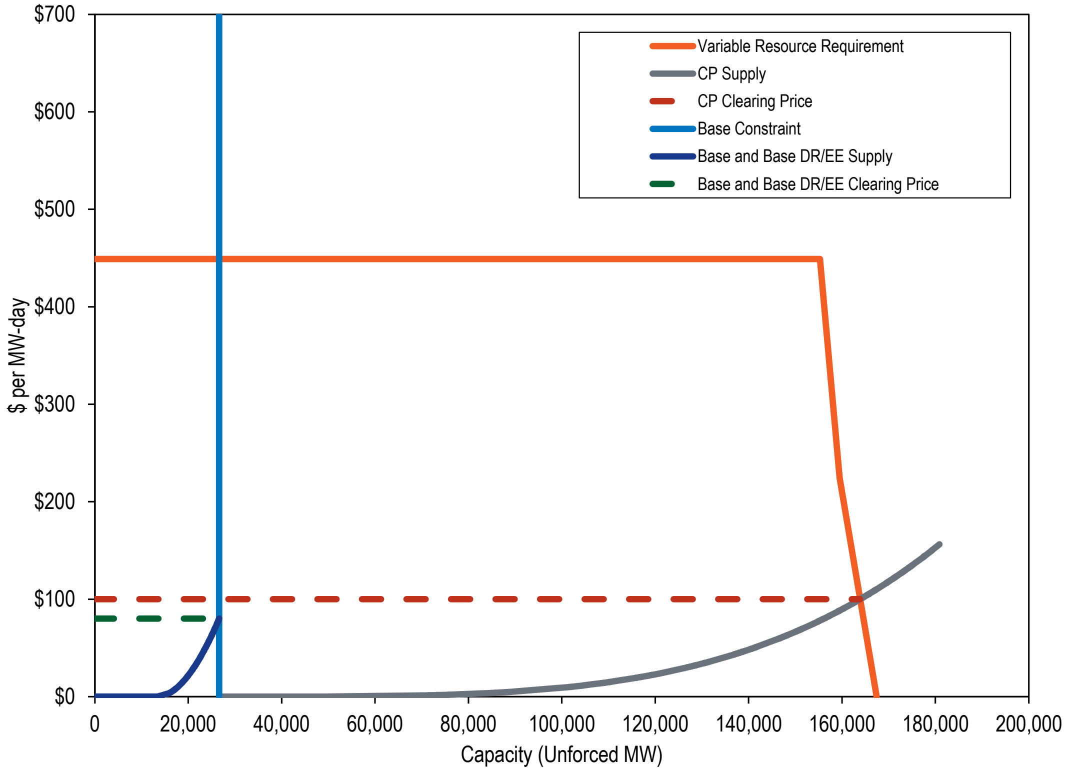
Table 36 Impact of all DR, Base Capacity Resources, and imports: 2019/2020 RPM Base Residual Auction (Scenario 15)

		Actual Auction Results		CP Gen Resources Only and Reduce Imports by 50 Percent	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3		
	Base Capacity	$80.00	16,807.3		
	Capacity Performance	$100.00	140,307.3	$210.12	161,511.0
RTO Total			167,305.9		161,511.0
EMAAC	Base Capacity DR/EE	$99.77	1,629.5		
	Base Capacity	$99.77	5,136.0		
	Capacity Performance	$119.77	24,003.8	$385.89	28,898.7
EMAAC Total			30,769.3		28,898.7
Pepco	Base Capacity DR/EE	$0.01	474.5		
	Base Capacity	$80.00	48.3		
	Capacity Performance	$100.00	5,725.6	$210.12	6,114.0
Pepco Total			6,248.4		6,114.0
ComEd	Base Capacity DR/EE	$182.77	1,945.2		
	Base Capacity	$182.77	1,216.3		
	Capacity Performance	$202.77	19,809.9	$248.47	22,002.8
ComEd Total			22,971.4		22,002.8
BGE	Base Capacity DR/EE	$80.30	252.9		
	Base Capacity	$80.30	346.5		
	Capacity Performance	$100.30	2,140.1	$210.12	2,800.1
BGE Total			2,739.5		2,800.1

Table 37 Impact of inconsistency between EE cleared MW and EE Add back MW (Scenario 7)

		Actual Auction Results		EE Add Back Equal to Cleared EE	
LDA	Product Type	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
RTO	Base Capacity DR/EE	$80.00	10,191.3	$80.00	10,160.2
	Base Capacity	$80.00	16,807.3	$80.00	16,803.2
	Capacity Performance	$100.00	140,307.3	$100.00	139,938.9
RTO Total			167,305.9		166,902.3
EMAAC	Base Capacity DR/EE	$99.77	1,629.5	$99.83	1,629.5
	Base Capacity	$99.77	5,136.0	$99.83	5,136.0
	Capacity Performance	$119.77	24,003.8	$119.83	23,941.4
EMAAC Total			30,769.3		30,706.9
Pepco	Base Capacity DR/EE	$0.01	474.5	$0.01	470.9
	Base Capacity	$80.00	48.3	$80.00	48.3
	Capacity Performance	$100.00	5,725.6	$100.00	5,530.1
Pepco Total			6,248.4		6,049.3
ComEd	Base Capacity DR/EE	$182.77	1,945.2	$182.71	1,945.2
	Base Capacity	$182.77	1,216.3	$182.71	1,216.3
	Capacity Performance	$202.77	19,809.9	$202.71	19,809.9
ComEd Total			22,971.4		22,971.4
BGE	Base Capacity DR/EE	$80.30	252.9	$80.00	252.9
	Base Capacity	$80.30	346.5	$80.00	346.5
	Capacity Performance	$100.30	2,140.1	$100.00	2,140.1
BGE Total			2,739.5		2,739.5

Figure 1 RTO market supply/demand curves: 2019/2020 RPM Base Residual Auction[135] [136] [137]

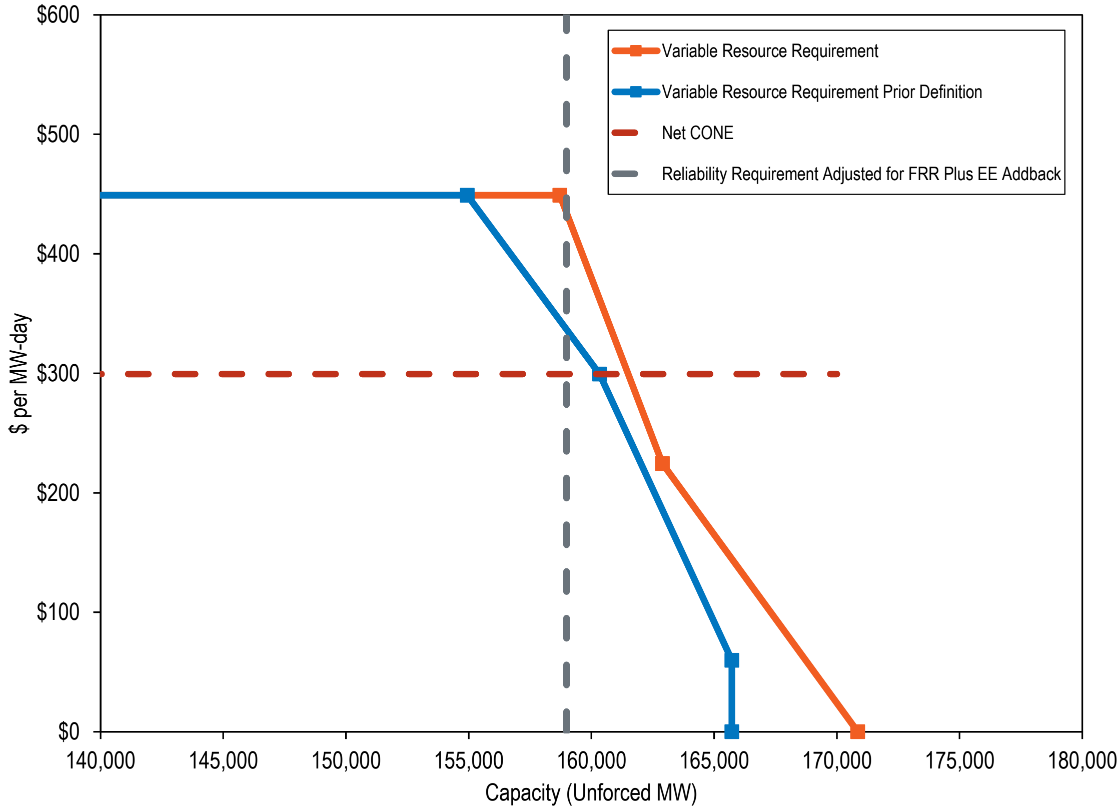


135 The supply curves presented in this report have all been smoothed using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all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

136 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in graphing the supply curve. The VRR curve and Base Capacity Constraint exclude incremental demand which cleared in EMAAC, ComEd, and BGE.

137 The Base Capacity Demand Resource Constraint was not a binding constraint in RTO in the 2019/2020 RPM Base Residual Auction.

Figure 2 RTO VRR curve shape comparison



EMAAC LDA Market Results

Table 38 shows total EMAAC LDA offer data for the 2019/2020 RPM Base Residual Auction. Total internal EMAAC LDA unforced capacity of 35,500.1 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 15, EMAAC LDA unforced internal capacity decreased 884.9 MW from 36,385.0 MW in the 2018/2019 BRA as a result of net generation capacity modifications (-968.2 MW), net DR modifications (-71.3 MW), and net EE modifications (118.3 MW), the EFORd effect due to lower sell offer EFORds (28.3 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (8.0 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO, so total EMAAC LDA RPM capacity was the same as the internal capacity of 35,500.1 MW.[138] RPM capacity was reduced by 671.0 MW of exports, 1,194.2

[138] PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), p. 52.

MW excused from the RPM must offer requirement, and 226.2 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (891.1 MW), the resource being considered existing for purposes of the RPM must offer requirement and mitigation only because it cleared an RPM Auction in a prior delivery year but is unable to achieve full commercial operation prior to the delivery year (281.0 MW), and capacity resource status change (22.1 MW). Subtracting 180.5 MW of DR and EE not offered resulted in available unforced capacity in EMAAC LDA of 33,228.2 MW.[139] After accounting for these exceptions, all capacity resources in EMAAC were offered in the RPM Auction.

The EMAAC LDA import limit was a binding constraint in the 2019/2020 BRA. Of the 30,769.3 MW cleared in EMAAC LDA, 29,879.9 MW were cleared in the RTO before EMAAC LDA became constrained. Once the constraint was binding, based on the 8,856.0 MW CETL value, only the incremental supply located in EMAAC LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 889.4 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $119.77 per MW-day, as shown in Figure 3. The clearing price was determined by the intersection of the incremental supply and VRR curve.

The Base Capacity Resource Constraint was a binding constraint for RTO in the 2019/2020 BRA, and as a result Base Capacity Resources and Base Capacity DR/EE Resources in EMAAC LDA received a clearing price of $99.77 per MW-day.

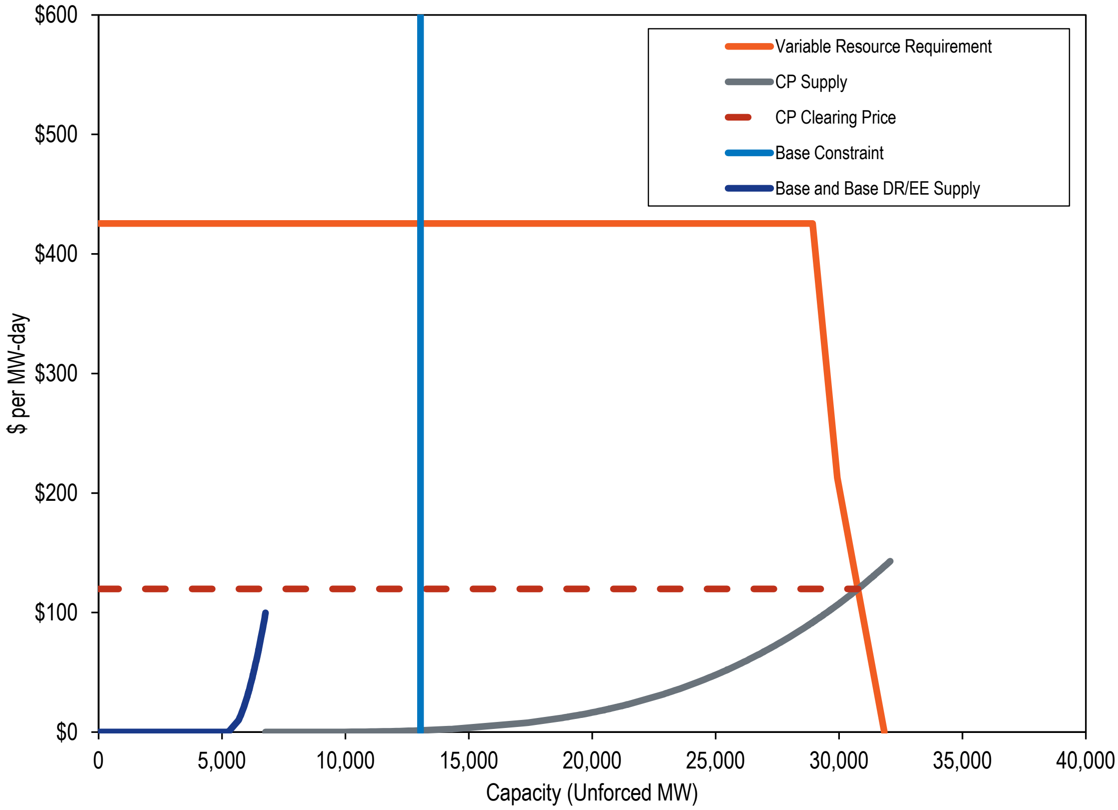
139 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for EMAAC LDA

Table 38 EMAAC LDA offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	35,263.5	33,328.0		
DR capacity	1,792.8	1,950.6		
EE capacity	204.1	221.5		
Total internal EMAAC LDA capacity	37,260.4	35,500.1		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	37,260.4	35,500.1		
Exports	(674.0)	(671.0)		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(1,556.9)	(1,194.2)		
Unoffered Planned Generation Capacity Resources	(246.0)	(226.2)		
Unoffered DR and EE	(166.7)	(180.5)		
Available	34,616.8	33,228.2	100.0%	100.0%
Generation offered	32,786.6	31,236.6	94.7%	94.0%
DR offered	1,640.9	1,786.1	4.7%	5.4%
EE offered	189.3	205.5	0.5%	0.6%
Total offered	34,616.8	33,228.2	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		29,879.9		89.9%
Cleared in EMAAC		889.4		2.7%
Total cleared		30,769.3		92.6%
Make whole		23.6		0.1%
Reliability requirement		37,633.0		
Total generation and DR cleared plus make whole		30,632.1		
CETL		8,856.0		
Total Resources		39,488.1		
Net excess/(deficit)		1,855.1		
Resource clearing price for Base Capacity DR/EE Resources ($ per MW-day)		$99.77		
Resource clearing price for Base Capacity Resources ($ per MW-day)		$99.77		
Resource clearing price for Capacity Performance Resources ($ per MW-day)		$119.77		
Preliminary zonal capacity price ($ per MW-day)		$116.62	A	
Base zonal CTR credit rate ($ per MW-day)		$2.33	B	
Preliminary net load price ($ per MW-day)		$114.29	A-B	

Figure 3 EMAAC LDA market supply/demand curves: 2019/2020 RPM Base Residual Auction[140] [141]



Pepco LDA Market Results

Table 39 shows total Pepco LDA offer data for the 2019/2020 RPM Base Residual Auction. Total internal Pepco LDA unforced capacity of 6,947.0 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 15, Pepco LDA unforced internal capacity increased 786.0 MW from 6,161.0 MW in the 2018/2019 BRA as a result of net generation capacity modifications (912.2 MW), net DR modifications (-157.4 MW),

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140 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in graphing the supply curve. The VRR curve is reduced by the CETL.

141 The Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint were not binding constraints in EMAAC LDA in the 2019/2020 RPM Base Residual Auction.

and net EE modifications (-1.1 MW), the EFORd effect due to lower sell offer EFORds (29.1 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (3.2 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO, so total Pepco LDA RPM capacity was the same as the internal capacity of 6,947.0 MW.[142] RPM capacity was reduced by 0.0 MW of exports, 0.0 MW excused from the RPM must offer requirement, and 67.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement. Subtracting 93.3 MW of DR and EE not offered resulted in available unforced capacity in Pepco LDA of 6,786.6 MW.[143] After accounting for these exceptions, all capacity resources in Pepco LDA were offered in the RPM Auction.

The Pepco LDA import limit was not a binding constraint in the 2019/2020 BRA. The Pepco LDA Base Capacity Demand Resource Constraint was binding in the 2019/2020 BRA. The Base Capacity Resource Constraint was binding for the RTO in the 2019/2020 BRA. As a result, the Pepco LDA clearing prices for Capacity Performance Resources and Base Capacity Resources were based on the RTO clearing prices, and the Pepco LDA clearing price for Base Capacity DR/EE Resources was based on the Pepco Base Capacity DR/EE Price Decrement. See Figure 4.

142 PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), p. 52.

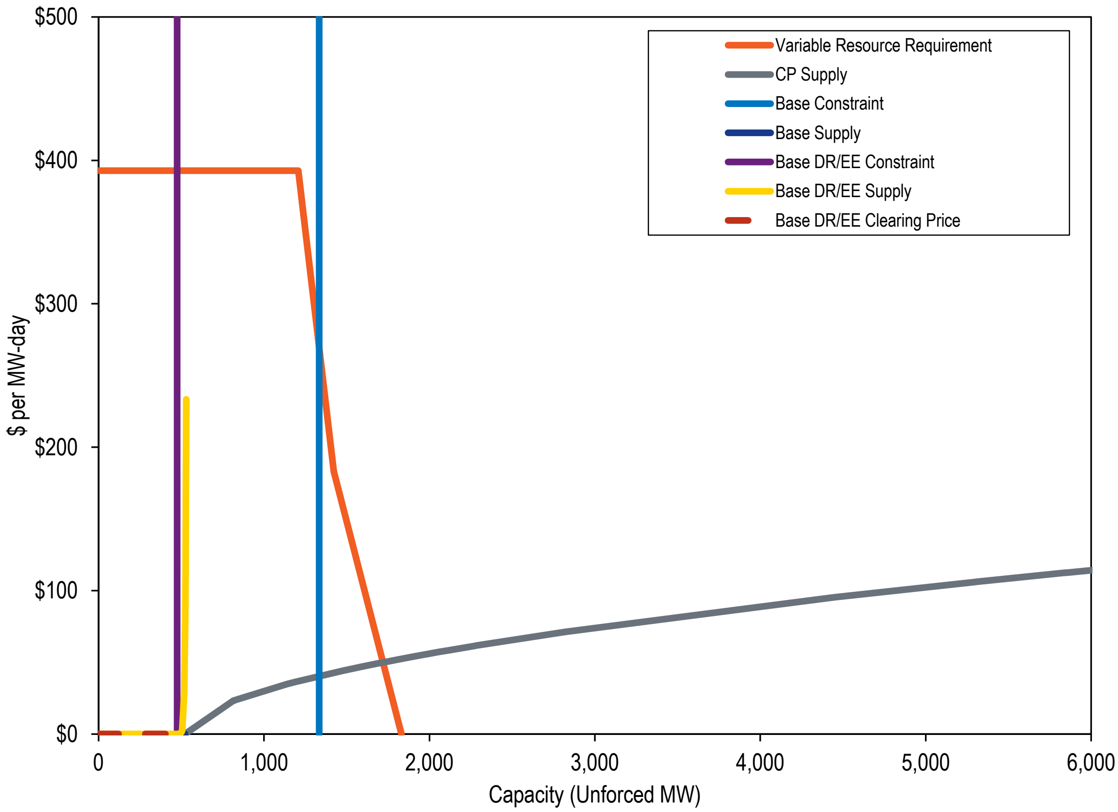
143 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for Pepco LDA

Table 39 Pepco LDA offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	6,628.0	6,198.1		
DR capacity	566.7	616.5		
EE capacity	121.5	132.4		
Total internal Pepco LDA capacity	7,316.2	6,947.0		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	7,316.2	6,947.0		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	(70.0)	(67.1)		
Unoffered DR and EE	(85.8)	(93.3)		
Available	7,160.4	6,786.6	100.0%	100.0%
Generation offered	6,558.0	6,131.0	91.6%	90.3%
DR offered	524.2	570.4	7.3%	8.4%
EE offered	78.2	85.2	1.1%	1.3%
Total offered	7,160.4	6,786.6	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		6,248.4		92.1%
Cleared in Pepco		0.0		0.0%
Total cleared		6,248.4		92.1%
Make whole		0.0		0.0%
Reliability requirement		8,074.0		
Total generation and DR cleared plus make whole		6,169.4		
CETL		6,985.0		
Total Resources		13,154.4		
Net excess/(deficit)		5,080.4		
Resource clearing price for Base Capacity DR/EE Resources ($ per MW-day)		$0.01		
Resource clearing price for Base Capacity Resources ($ per MW-day)		$80.00		
Resource clearing price for Capacity Performance Resources ($ per MW-day)		$100.00		
Preliminary zonal capacity price ($ per MW-day)		$91.64	A	
Base zonal CTR credit rate ($ per MW-day)		$0.00	B	
Preliminary net load price ($ per MW-day)		$91.64	A-B	

Figure 4 Pepco LDA market supply/demand curves: 2019/2020 RPM Base Residual Auction[144 145]



ComEd LDA Market Results

Table 40 shows total ComEd LDA offer data for the 2019/2020 RPM Base Residual Auction. Total internal ComEd LDA unforced capacity of 27,811.1 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 15, ComEd LDA unforced internal capacity increased 353.0 MW from 27,458.1 MW in the 2018/2019 BRA as a result of net generation capacity modifications (45.0 MW), net DR modifications (-236.4 MW),

144 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in graphing the supply curve. The VRR curve is reduced by the CETL.

145 The import limit and the Base Capacity Resource Constraint were not binding constraints in Pepco LDA in the 2019/2020 RPM Base Residual Auction.

and net EE modifications (-27.5 MW), the EFORd effect due to lower sell offer EFORds (560.4 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (11.5 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO.[146] Total internal ComEd LDA capacity was reduced by FRR commitments of 29.0 MW, resulting in ComEd LDA RPM capacity of 27,782.1 MW. RPM capacity was reduced by 534.7 MW of exports, 0.5 MW of FRR optional volumes not offered, 476.0 MW excused from the RPM must offer requirement, and 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement. Subtracting 182.2 MW of DR and EE not offered resulted in available unforced capacity in ComEd LDA of 26,588.7 MW.[147] After accounting for these exceptions, all capacity resources in ComEd LDA were offered in the RPM Auction.

The ComEd LDA import limit was a binding constraint in the 2019/2020 BRA. Of the 22,971.4 MW cleared in ComEd LDA, 20,606.6 MW were cleared in the RTO before ComEd LDA became constrained. Once the constraint was binding, based on the 5,160.0 MW CETL value, only the incremental supply located in ComEd LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 2,364.8 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $202.77 per MW-day, as shown in Figure 5. The clearing price was determined by the intersection of the incremental supply and VRR curve.

The Base Capacity Resource Constraint was a binding constraint for RTO in the 2019/2020 BRA, and as a result Base Capacity Resources and Base Capacity DR/EE Resources in ComEd LDA received a clearing price of $182.77 per MW-day.

[146] PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), p. 52.

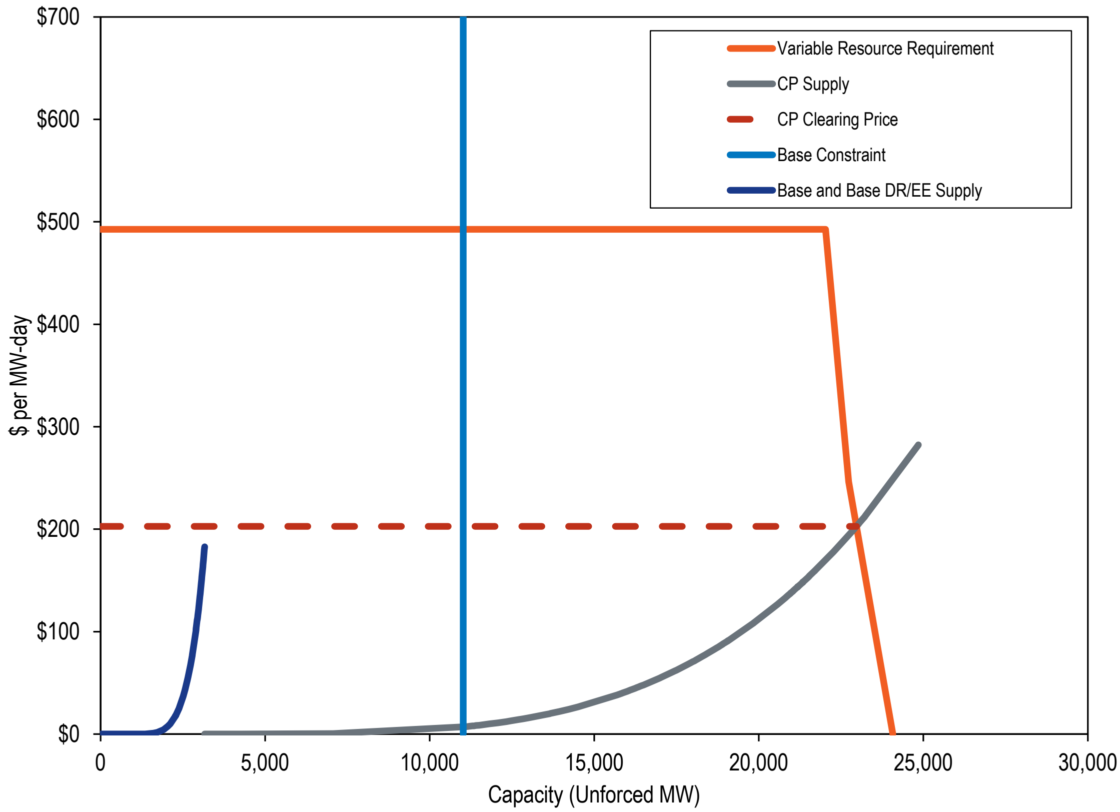
[147] Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figures for ComEd LDA

Table 40 ComEd LDA offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	26,078.9	25,111.8		
DR capacity	1,814.4	1,974.3		
EE capacity	666.2	725.0		
Total internal ComEd LDA capacity	28,559.5	27,811.1		
FRR	(29.0)	(29.0)		
Imports	0.0	0.0		
RPM capacity	28,530.5	27,782.1		
Exports	(544.4)	(534.7)		
FRR optional	(0.5)	(0.5)		
Excused Existing Generation Capacity Resources	(500.0)	(476.0)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered DR and EE	(167.7)	(182.2)		
Available	27,317.9	26,588.7	100.0%	100.0%
Generation offered	25,005.0	24,071.6	91.5%	90.5%
DR offered	1,646.7	1,792.0	6.0%	6.7%
EE offered	666.2	725.1	2.4%	2.7%
Total offered	27,317.9	26,588.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		20,606.6		77.5%
Cleared in ComEd		2,364.8		8.9%
Total cleared		22,971.4		86.4%
Make whole		0.0		0.0%
Reliability requirement		26,509.0		
Total generation and DR cleared plus make whole		22,246.6		
CETL		5,160.0		
Total Resources		27,406.6		
Net excess/(deficit)		897.6		
Resource clearing price for Base Capacity DR/EE Resources ($ per MW-day)		$182.77		
Resource clearing price for Base Capacity Resources ($ per MW-day)		$182.77		
Resource clearing price for Capacity Performance Resources ($ per MW-day)		$202.77		
Preliminary zonal capacity price ($ per MW-day)		$199.54	A	
Base zonal CTR credit rate ($ per MW-day)		$9.56	B	
Preliminary net load price ($ per MW-day)		$189.99	A-B	

Figure 5 ComEd LDA market supply/demand curves: 2019/2020 RPM Base Residual Auction[148] [149]



BGE LDA Market Results

Table 41 shows total BGE LDA offer data for the 2019/2020 RPM Base Residual Auction. Total internal BGE LDA unforced capacity of 4,166.4 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 15, BGE LDA unforced internal capacity decreased 202.5 MW from 4,368.9 MW in the 2018/2019 BRA as a result of net generation capacity modifications (-48.5 MW), net DR modifications (-109.4 MW), and

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148 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in graphing the supply curve. The VRR curve is reduced by the CETL.

149 The Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint were not binding constraints in ComEd LDA in the 2019/2020 RPM Base Residual Auction.

net EE modifications (-90.5 MW), the EFORd effect due to lower sell offer EFORds (42.3 MW), and the DR and EE effect due to a higher Load Management UCAP conversion factor (3.6 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO, so total BGE LDA RPM capacity was the same as the internal capacity of 4,166.4 MW.[150] RPM capacity was reduced by 0.0 MW of exports, 0.0 MW excused from the RPM must offer requirement, and 0.0 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement. Subtracting 65.7 MW of DR and EE not offered, resulted in available unforced capacity in BGE LDA of 4,100.7 MW.[151] After accounting for these exceptions, all capacity resources in BGE LDA were offered in the RPM Auction.

The BGE LDA import limit was a binding constraint in the 2019/2020 BRA. Of the 2,739.5 MW cleared in BGE LDA, 2,739.5 MW were cleared in the RTO before BGE LDA became constrained. Once the constraint was binding, based on the 6,234.7 MW CETL value, only the incremental supply located in BGE LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 0.0 MW cleared, which resulted in a clearing price for Capacity Performance Resources of $100.30 per MW-day, as shown in Figure 6. The clearing price was determined by the intersection of the incremental supply and VRR curve.

The Base Capacity Resource Constraint was a binding constraint for RTO in the 2019/2020 BRA, and as a result Base Capacity Resources and Base Capacity DR/EE Resources in BGE LDA received a clearing price of $80.30 per MW-day.

150 PJM. "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), p. 52.

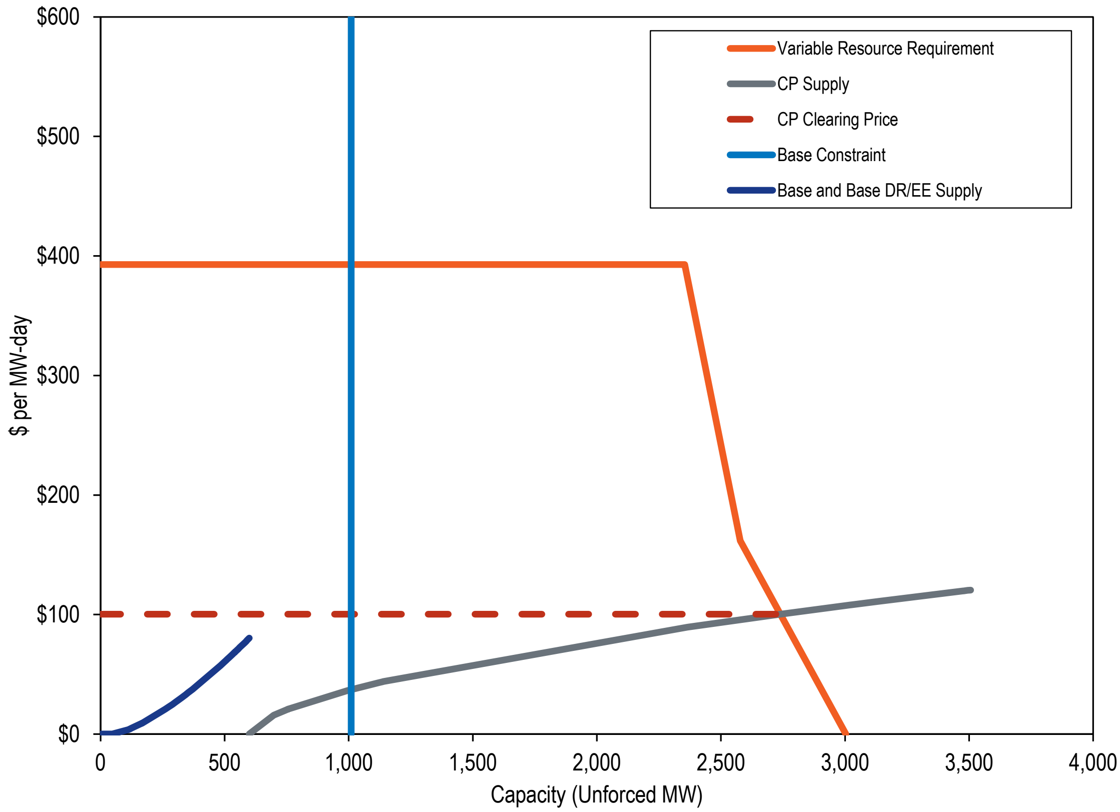
151 Unoffered DR and EE MW include PJM approved DR and EE plans that were not offered in the auction.

Table and Figure for BGE LDA

Table 41 BGE LDA offer statistics: 2019/2020 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	3,535.8	3,270.7		
DR capacity	730.5	794.9		
EE capacity	92.8	100.8		
Total internal BGE LDA capacity	4,359.1	4,166.4		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	4,359.1	4,166.4		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered DR and EE	(60.6)	(65.7)		
Available	4,298.5	4,100.7	100.0%	100.0%
Generation offered	3,535.8	3,270.7	82.3%	79.8%
DR offered	669.9	729.3	15.6%	17.8%
EE offered	92.8	100.7	2.2%	2.5%
Total offered	4,298.5	4,100.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		2,739.5		66.8%
Cleared in BGE		0.0		0.0%
Total cleared		2,739.5		66.8%
Make whole		0.0		0.0%
Reliability requirement		8,401.0		
Total cleared generation and DR plus make whole		2,638.8		
CETL		6,234.7		
Total Resources		8,873.5		
Net excess/(deficit)		472.5		
Resource clearing price for Base Capacity DR/EE Resources ($ per MW-day)		$80.30		
Resource clearing price for Base Capacity Resources ($ per MW-day)		$80.30		
Resource clearing price for Capacity Performance Resources ($ per MW-day)		$100.30		
Preliminary zonal capacity price ($ per MW-day)		$97.07	A	
Base zonal CTR credit rate ($ per MW-day)		$0.18	B	
Preliminary net load price ($ per MW-day)		$96.89	A-B	

Figure 6 BGE LDA market supply/demand curves: 2019/2020 RPM Base Residual Auction[152 153]



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152 For uncleared coupled offers, the offer with the lowest sell offer price within a coupled segment group was used in graphing the supply curve. The VRR curve is reduced by the CETL.

153 The Base Capacity Resource Constraint and the Base Capacity Demand Resource Constraint were not binding constraints in BGE LDA in the 2019/2020 RPM Base Residual Auction.

Attachment A

Clearing Algorithm for RPM Base Residual Auction

The actual clearing of the RPM Base Residual Auction (BRA) uses a mixed integer optimization algorithm. The purpose of the algorithm is to minimize the cost of procuring unforced capacity given all applicable requirements and constraints, including transmission limits between LDAs, restrictions on coupled sell offers and restrictions specified in credit limited offers.[154] The optimization algorithm calculates clearing prices, which are derived from the shadow prices of the binding resource constraints.

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

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

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[154] OATT Attachment DD § 5.12(a).

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

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

Possible Reasons for Differences between PJM and MMU Solutions

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

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

Comparison of PJM and MMU Solutions

The results of the 2019/2020 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every constrained nested LDA using the MMU's algorithm is identical to the corresponding total MW cleared under PJM's method. The total MW cleared for the entire RTO using the MMU's algorithm is identical to the total MW cleared under PJM's method. The clearing prices using the MMU's approach were within 0.02 percent of the corresponding clearing prices under PJM's method.

Recommendations

The MMU recommends two changes to the RPM solution methodology that address make whole payments and the iterative reconfiguration of the VRR curve. These changes will result in a simpler approach to the optimization problem, which will improve the stability, transparency, and manageability of the RPM market clearing.

The first change would address the fact that the current RPM solution method does not explicitly include the cost of make whole payments in its objective function. Instead, the model handles inflexible offers as part of an iterative process and make whole payments are determined at the end. Because the additional make whole payments are excluded from the optimization objective function, the model does not optimally balance the system to accommodate the extra cost and the extra MW of make whole payments as part of the optimization. The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. The model would be able to choose the lower cost option of an inflexible offer and a higher priced flexible offer. The MMU's testing has shown that the proposed approach solves as fast and results in a better solution defined by overall system benefit.

Once make whole payments are incorporated into the optimization model, a reevaluation of how Marginal Clearing Prices (MCP) are determined would be required. Currently, the MCP calculations are based on shadow prices, such that the MCP equals the marginal offer price if the marginal offer clears partially and is greater than the marginal offer price if the marginal offer clears wholly. Adding a make whole variable to the model will affect the resulting shadow prices, because the objective function internalizes the cost of make whole payments. As a result, the condition that MCP equals the offer price of the partially cleared resource on the margin and is greater than the offer price of all other cleared resources may no longer hold. Therefore, this enhancement necessitates a reevaluation of how MCPs are determined.

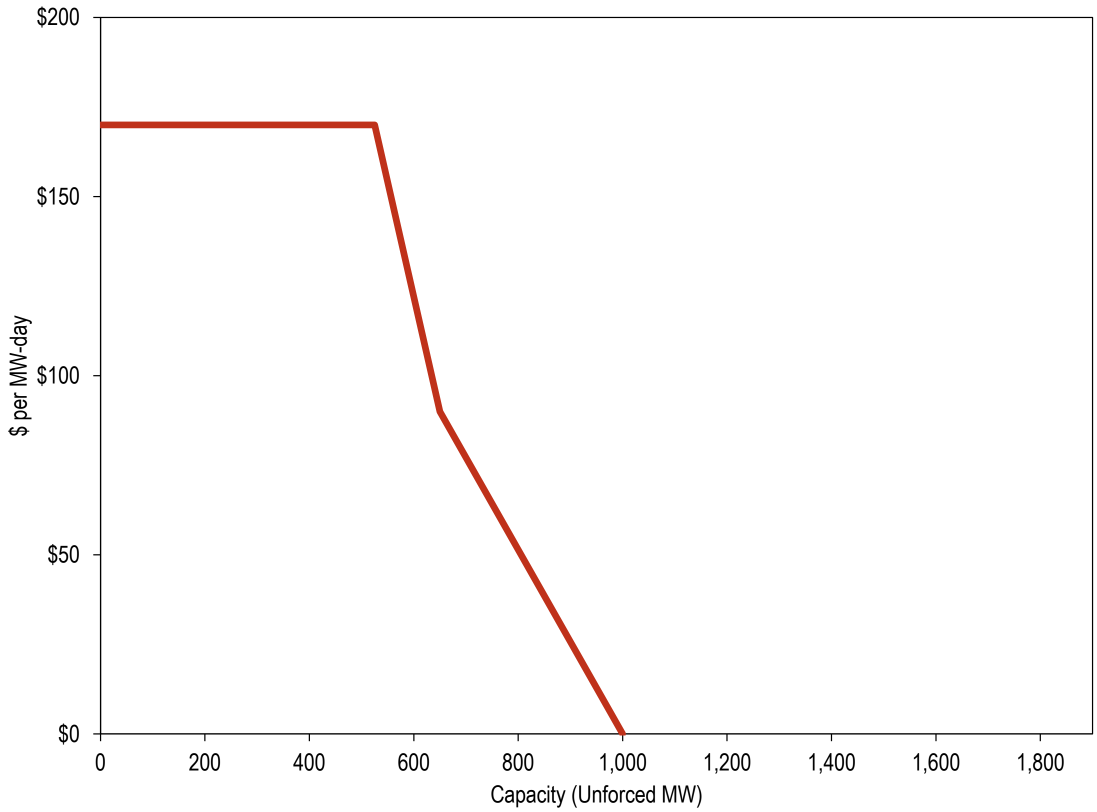
The second change would improve the efficiency and stability of the RPM optimization. Currently, PJM's RPM model uses a nested LDA structure, in which the capacity procured towards meeting a child LDA's VRR also satisfies the nested parent LDA's VRR. To respect this relationship, the mixed integer optimization problem is solved iteratively, where after every iteration, the parent LDAs' VRR curves are reconfigured to reflect their respective child LDAs' cleared capacity. The process is repeated until a convergence point, based on the difference in cleared capacity for each LDA from one iteration to the next, is reached. The purpose of the iterative approach is to jointly optimize the cost of procuring a child LDA's and the parent LDA's capacity to meet their respective VRRs. However, the joint optimization can be accomplished more efficiently with a simultaneous rather than an iterative approach by defining variables for the nesting relationships. The MMU recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability of the solution.

Illustration of BRA Clearing Algorithm

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

Figure 7 and Figure 8 show an example child VRR and parent VRR curves. To illustrate the price formation in the BRA, two example scenarios are presented. In the first scenario, a higher CETL is assumed between the parent LDA and the child LDA. In the second scenario, a lower CETL is assumed between the parent LDA and the child LDA. All other offers and parameters are identical in the two scenarios. In both scenarios, only one type of resource and only one requirement are considered.[155]

Figure 7 Variable Resource Requirement Curve: Child LDA



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

Figure 8 Nested Variable Resource Requirement Curve: Parent LDA

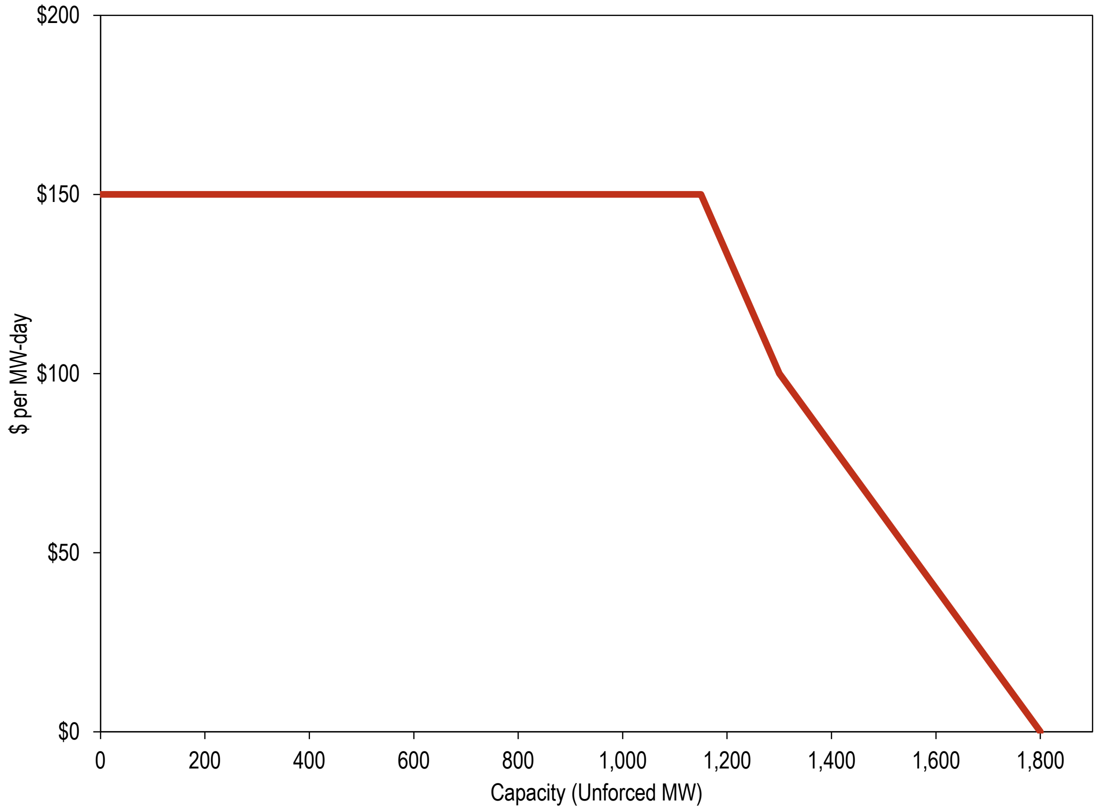


Figure 9 and Figure 10 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both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

Figure 9 Optimal solution for scenario 1: Child LDA

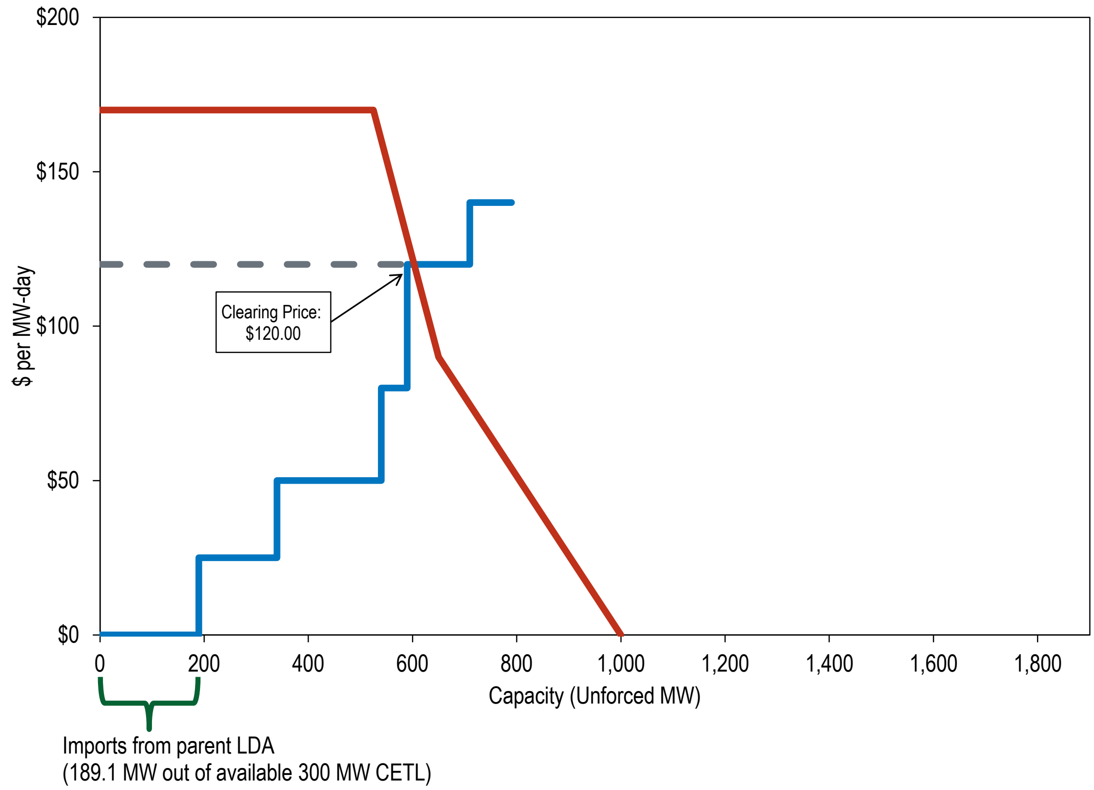


Figure 10 Optimal solution for scenario 1: Parent LDA

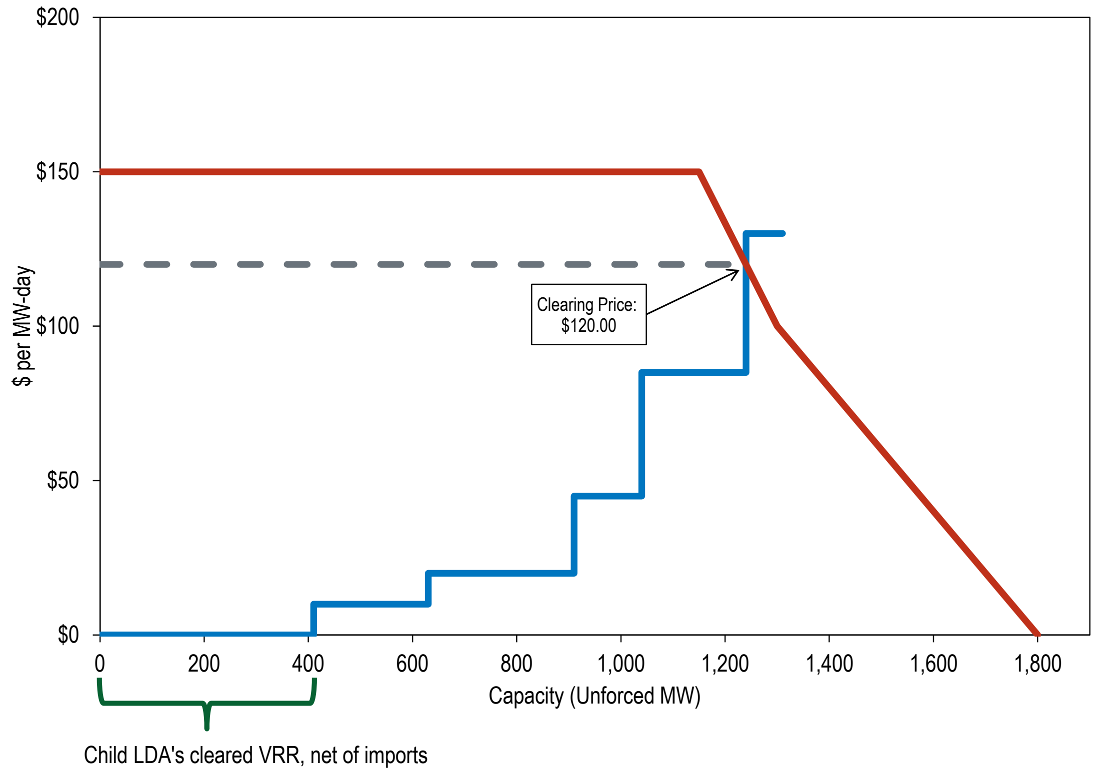


Figure 11 and Figure 12 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA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

Figure 11 Optimal solution for scenario 2: Child LDA

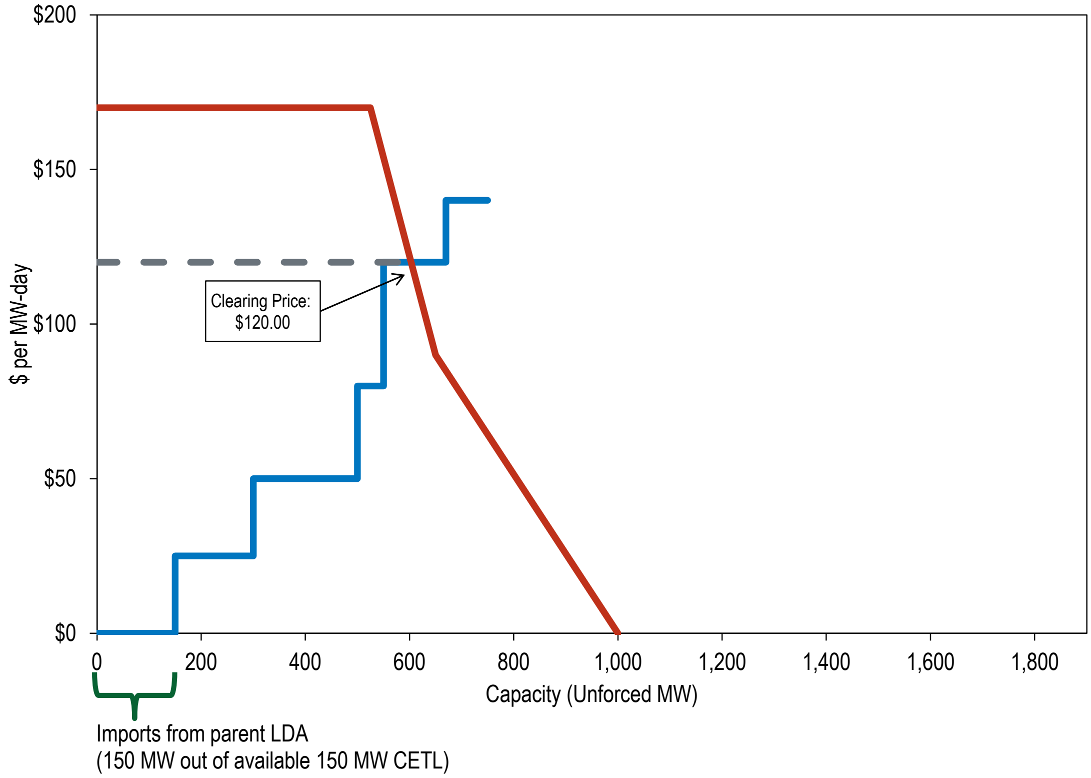
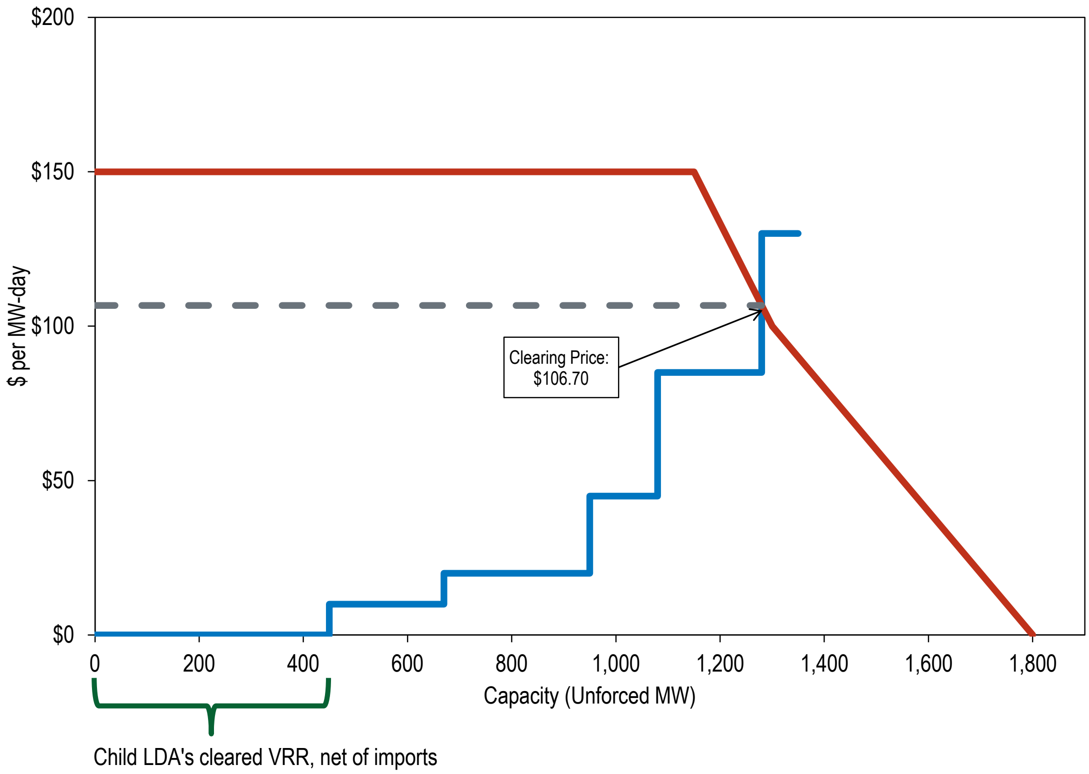


Figure 12 Optimal solution for scenario 2: Parent LDA



Attachment B

Competitive offer for a Capacity Performance resource in PJM

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

Definitions

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

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

A_i = (MWh_i/UCAP), availability during performance assessment hour i

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

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

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

H – Expected value of total number of performance assessment hours in a delivery year

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

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

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

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

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

Competitive Offer for an underperforming resource

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

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

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

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

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

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

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

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

Low ACR case

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

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

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

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

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

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

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

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

Using the weighted average capacity performance bonus rate,

$$p \geq PPR \times H \times \bar{B} + CPBR \times H \times \bar{A} - PPR \times H \times \bar{A}$$

Therefore the competitive offer is:

$$p = CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}) \quad (3)$$

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

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

$$p = CPBR \times H \times \bar{A} + \left(\frac{Net\ CONE}{30}\right) \times H \times (\bar{B} - \bar{A}) \quad (4)$$

If (i) the capacity performance bonus rate is assumed to be equal to the capacity non-performance charge rate and, (ii) the number of expected performance hours is expected to be 30, this is identical to:

$$p = Net\ CONE \times \bar{B} \quad (5)$$

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing.

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

High ACR case

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

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

$$or\ ACR > CPBR \times H \times \bar{A}$$

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

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

From equation (1):

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

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

The competitive offer is:

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

The competitive offer for a High ACR unit equals avoidable costs plus expected non-performance charges.

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

Competitive Offer for an overperforming resource

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

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

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

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

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

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

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

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

Low ACR case

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

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

$$or\ ACR \leq CPBR \times H \times \bar{A}$$

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

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

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

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

$$or,\ p \geq\ CPBR \times H \times \bar{B} \tag{9}$$

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

If (i) the capacity performance bonus rate is assumed to be equal to the capacity non-performance charge rate (Net CONE divided by 30) and, (ii) the number of expected performance hours is expected to be 30, this is identical to:

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

These are the assumptions made in the PJM filing and result in the definition of the competitive offer cap in the PJM filing.

High ACR case

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

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

$$or\ ACR > CPBR \times H \times \bar{A}$$

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

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

From equation (7):

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

$$or, \qquad p \geq ACR + CPBR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

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

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

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

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

Revision History

August 31, 2016: Original document posted.

September 12, 2016: The following edits were made:

- Table 17, "The ~~PPL~~BGE clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $80.00 per MW-day, and the clearing quantity would have remained the same at 599.4 MW."

- Page 53, "The Pepco clearing price for Base Capacity Resources would have increased to $84.00 per MW-day, and the clearing quantity would have decreased to ~~474.5~~ 21.9 MW. The Pepco clearing price for Base Capacity DR/EE Resources would have remained the same at $0.01 per MW-day, and the clearing quantity would have remained the same at 474.5 MW. The ComEd clearing price for Capacity Performance Resources would have decreased to ~~$120.00~~ $140.00 per MW-day, and the clearing quantity would have decreased to 18,436.4 MW. The ComEd clearing price for Base Capacity Resources and Base Capacity DR/EE Resources would have decreased to $120.00 per MW-day, and the clearing quantity would have decreased to 3,017.0 MW."

- Page 55, "The ComEd clearing price for Capacity Performance Resources would have ~~remained~~ increased to $204.15 per MW-day, and the clearing quantity would have increased to 19,856.9 MW."

- Page 60, "The clearing price for Capacity Performance Resources and Base Capacity Resources would have increased to ~~$130.00~~ $130.96 per MW-day, and the clearing quantity would have increased to 3,224.7 MW."

- Page 66, "The BGE clearing price for Capacity Performance Resources would have increased to ~~$107.06~~ $102.20 per MW-day, and the clearing quantity would have remained the same at 2,140.1 MW."

- Page 67, "The Pepco clearing price for Capacity Performance Resources would have increased to ~~$100.00~~ $110.00 per MW-day, and the clearing quantity would have increased to 5,859.9 MW."

- Page 70, "The RTO clearing price for Capacity Performance Resources would have remained the same at $100.00 per MW-day, and the clearing quantity would have decreased to ~~166,902.3~~ 139,938.9 MW."