



Monitoring
Analytics

Analysis of the 2017/2018 RPM Base Residual Auction

The Independent Market Monitor for PJM

October 6, 2014

Introduction

This report, prepared by the Independent Market Monitor for PJM (IMM or MMU), reviews the functioning of the eleventh Reliability Pricing Model (RPM) Base Residual Auction (BRA) (for the 2017/2018 Delivery Year) 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 Short-Term Resource Procurement Target; Demand Resources (DR); the definition of Demand Resource products; Avoidable Project Investment Recovery Rate (APIR) changes related to environmental regulations; and capacity imports.

Conclusions and Recommendations

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. 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 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 existing 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). This represents a significant advance over the prior capacity market design.

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 MMU verified the reasonableness of cost data and calculated the derived offer caps based on submitted data; calculated unit net revenues; 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; verified the sell offer Equivalent Demand Forced Outage Rates (EFORs); reviewed requests for alternate maximum EFORs; verified clearing prices based on the demand (VRR) curves and the Demand Resource Constraints; and verified that the market structure tests were applied correctly.¹ All participants in the RTO and PSEG RPM markets failed the three pivotal supplier (TPS) 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.^{2 3} The offer caps are designed to reflect the marginal cost of

¹ 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.

² 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.

³ 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).

capacity. Based on the data and this review, the MMU concludes that the results of the 2017/2018 RPM Base Residual Auction were competitive, with the caveat that there continue to be significant issues with the capacity market design which have significant consequences for market outcomes.

In particular, the MMU recommends that the use of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target) be terminated immediately. 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.^{4 5} The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends 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.⁶ The MMU recommends 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. Both the Limited and the Extended Summer DR products should be eliminated and the restrictions on the availability of Annual DR should 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 remaining Annual DR should be on the demand side of the market rather than on the supply side. The MMU recommends 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 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

⁴ See Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000. (December 20, 2013).

⁵ 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).

⁶ See the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

operating blocks that are not a result of actual unit limitations.^{7 8} 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.⁹

The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve.¹⁰ 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 BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability.

⁷ See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) (“Triennial Review”).

⁸ See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

⁹ See 143 FERC ¶ 61,090 (2013) (“We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE.”); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

¹⁰ For more details on these recommendations, see Attachment A.

Results

The 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 6, the 167,003.7 MW of cleared resources for the entire RTO, which represented a reserve margin of 20.1 percent not considering Fixed Resource Requirement (FRR) load, resulted in net excess of 6,187.0 MW over the reliability requirement of 165,007.1 MW.¹¹

The Short-Term Resource Procurement Target had a significant impact on the auction results. The removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for all the RPM LDA markets. The clearing quantities of Annual Resources, including generation and DR, were reduced as a result of the 2.5 percent demand reduction. Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,947,329,539, an increase of \$2,435,099,909, or 32.4 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target resulted in a 24.5 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the 2.5 percent reduction in demand. If the VRR curves and Demand Resource Constraints had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,967,834,187, an increase of \$2,455,604,557, or 32.7 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target resulted in a 24.6 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the 2.5 percent reduction of demand.¹²

¹¹ This calculation of the reserve margin excludes the Short-Term Resource Procurement Target from the peak load forecast and from cleared MW. The excess is defined relative to 97.5 percent of the peak load forecast.

¹² These results were also reported in: *The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised*, Monitoring Analytics, LLC (August 26, 2014) <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf>

The inclusion of Limited and Extended Summer DR products in the auction also 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 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If only generation, Annual DR, and Energy Efficiency (EE) resources were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,738,222,922, an increase of \$2,225,993,292, or 29.6 percent, compared to the actual results. From another perspective, the inclusion of the Limited and Extended Summer DR products resulted in a 22.9 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the Limited and Extended Summer DR products.

The combination of the Short-Term Resource Procurement Target and Limited and Extended Summer DR products 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 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$10,932,522,889, an increase of \$3,420,293,259, or 45.5 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products resulted in a 31.3 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the Short-Term Resource Procurement Target or the Limited and Extended Summer DR products.

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 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$16,859,658,203, an increase of \$9,347,428,573, or 124.4 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 55.4 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

The inclusion of sell offers for Annual DR and 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 2017/2018 RPM Base Residual Auction were

\$7,512,229,630. If only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,738,222,922. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$16,859,658,203, an increase of \$7,121,435,281, or 73.1 percent, compared to the results with only generation, Annual DR, and EE. The inclusion of sell offers for Annual DR and EE resulted in a 42.2 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to the revenues without any demand side products.

This is the best measure of the competitive impact of demand side products on the RPM market. The Annual 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 meets appropriate measurement and verification standards and that the DR was offered with the intention of providing physical resources, competition from the Annual DR product and Energy Efficiency resources resulted in a 42.2 percent reduction of payments for capacity. This demonstrates that Annual DR together with 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 Annual DR product, DR has a significant and appropriate competitive impact on capacity market outcomes although 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. As in prior BRAs, Extended Summer and Limited DR products also had a significant impact in the 2017/2018 BRA, but those impacts resulted from badly defined and inferior products.

The level of DR products that buy out of their positions after the BRA however suggests that the impact of DR on generation investment incentives needs to be carefully considered and the rules governing the requirement to be a physical resource are enforced.¹³ 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

¹³ 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).

available in Incremental Auctions. This would suppress the price of capacity in the BRA compared to 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 investments based on environmental regulation compliance, including the EPA's Mercury and Air Toxics Standards (MATS) rules and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) rules and the NJ High Electric Demand Day (HEDD) Rule, had a small impact on the auction results. Of the 11,449.8 MW of uncleared offers for generation resources, 4,245.6 MW were offers for resources that included costs associated with environmental regulation compliance that were not previously included in APIR. Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the APIR associated with the pending environmental regulations which had not been previously submitted were removed and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$7,531,360,041, an increase of \$19,130,411, or 0.3 percent, compared to the total based on actual results. From another perspective, the impact of including environmental compliance costs in APIR was to decrease total market revenues by \$19,130,411, or 0.3 percent.

The inclusion of capacity imports in the 2017/2018 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 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$8,210,054,013, an increase of \$697,824,383, or 9.3 percent, compared to the actual results. The impact of including 75 percent of the offers for external generation resources was to decrease total market revenues by \$697,824,383, or 8.5 percent. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$10,202,534,135, an increase of \$2,690,304,504, or 35.8 percent, compared to the actual results. The impact of including 25 percent of the offers for external generation resources was to decrease total market revenues by \$2,690,304,504, or 26.4 percent.

Of the 4,944.7 MW offered by external generation resources in the 2017/2018 RPM Base Residual Auction, 963.9 MW or 19.5 percent were not or did not plan to be pseudo tied. If offers for external generation resources that were not or did not plan to be pseudo tied were excluded and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$7,785,489,989, an increase of \$273,260,359, or 3.6 percent, compared to the actual results. The impact of

including external generation resources without pseudo ties was to decrease total market revenues by \$273,260,359, or 3.5 percent. The impact of increased imports is comparatively high in the RTO because all imports are considered to be imports to the RTO.

Clearing Prices

Table 1 shows the clearing prices for Annual Resources in the 2017/2018 BRA by LDA compared to the corresponding net Cost of New Entry (CONE) values. The clearing prices for Annual Resources were less than net CONE for every Locational Deliverability Area (LDA).

Table 1 Clearing prices and net CONE: 2017/2018 RPM Base Residual Auction

LDA	Annual Clearing Price (\$ per MW-day)	Net CONE (\$ per MW-day)	Annual Clearing Price to Net CONE
RTO	\$120.00	\$351.39	34.2%
MAAC	\$120.00	\$313.00	38.3%
EMAAC	\$120.00	\$365.87	32.8%
SWMAAC	\$120.00	\$313.00	38.3%
PSEG	\$215.00	\$365.87	58.8%
PSEG North	\$215.00	\$365.87	58.8%
DPL South	\$120.00	\$365.87	32.8%
Pepco	\$120.00	\$313.00	38.3%
ATSI	\$120.00	\$373.75	32.1%
ATSI Cleveland	\$120.00	\$373.75	32.1%
ComEd	\$120.00	\$373.75	32.1%
BGE	\$120.00	\$313.00	38.3%
PPL	\$120.00	\$354.46	33.9%

Market Changes

RPM Market Design Changes

External Generation Resources

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.¹⁴ Capacity Market Sellers may request an exception to the CIL for an external

¹⁴ 147 FERC ¶ 61,060 (2014).

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.

RPM Must Offer Requirement and Market Power Mitigation

The 2017/2018 RPM Base Residual Auction was the fourth BRA conducted under the revised RPM rules effective January 31, 2011, related to the RPM must-offer requirement and market power mitigation.¹⁵ 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 2017/2018 RPM Base Residual Auction was the second BRA conducted under the process related PJM Tariff revisions.¹⁶ 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.¹⁷ The rationale for the earlier deadline is to allow new entrants adequate time to respond and enter the PJM generation interconnection queue. Previously, the deadline for requesting an exception to the RPM must offer requirement based on the reason of retirement was 120 days prior to the auction. For the 2017/2018 BRA, a transition mechanism applied under which the deadline for requesting an exception to the RPM must offer requirement due to planned retirement was November 1, 2013. For all Base Residual Auctions for Delivery Years subsequent to 2017/2018, the deadline will be September 1 prior to the auction.

¹⁵ 134 FERC ¶ 61,065 (2011).

¹⁶ Letter Order in FERC Docket No. ER13-149 (November 28, 2012).

¹⁷ 145 FERC ¶ 61,035 (2013).

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.¹⁸ 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 percentage 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 2017/2018 RPM Base Residual Auction was the fourth 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.¹⁹

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.²⁰ The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those 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

¹⁸ 135 FERC ¶ 61,022 (2011).

¹⁹ 135 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.

²⁰ 143 FERC ¶ 61,090 (2013).

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.^{21 22 23} The 2017/2018 RPM Base Residual Auction was the second 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 2017/2018 RPM Base Residual Auction was the first BRA conducted using the revised ACR technology classifications. The default ACR values for the 2017/2018 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2013/2014 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 2014/2015 through 2016/2017 prior to estimating the default ACR values for the 2017/2018 Delivery Year.

Gross CONE

Effective January 20, 2013, the gross CONE values for the 2015/2016 Delivery Year were updated as part of a Settlement Agreement.²⁴ Between triennial 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.

²¹ 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).

²² PJM Interconnection, L.L.C., Docket No. ER13-529 (December 7, 2012) at 19.

²³ 142 FERC ¶ 61,092 (2013).

²⁴ 142 FERC ¶ 61,079 (2013).

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.²⁵

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.²⁶ 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.²⁷ 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.²⁸ 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

²⁵ 143 FERC ¶ 61,076 (2013).

²⁶ 134 FERC ¶ 61,066 (2011).

²⁷ The LDAs for which Minimum Resource Requirements are established was subsequently revised. See 135 FERC ¶ 61,102 (2011).

²⁸ See PJM filing initiating FERC Docket No. ER13-486-000 (November 30, 2012).

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.^{29 30} 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 new 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.³¹ 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 is not subtracted from the Minimum Annual and Extended Summer Resource Requirements.³² 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 is subtracted from the amount of Limited DR procured in the BRA, assuming either the Minimum Annual

²⁹ Letter Order issued in Docket No. ER11-2913-000 (April 13, 2011).

³⁰ PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 71-72.

³¹ PJM. "Manual 18: PJM Capacity Market," Revision 19 (June 1, 2013), p. 71.

³² 138 FERC ¶ 61,062 (2012).

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.³³ 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.³⁴ 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.

Preliminary Market Structure Screen

The preliminary market structure screen (PMSS) was eliminated effective December 17, 2012.³⁵ The 2017/2018 RPM Base Residual Auction was the second BRA held after the PMSS was eliminated.

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

³³ 146 FERC ¶ 61,052 (2014).

³⁴ 146 FERC ¶ 61,150 (2014).

³⁵ Letter Order issued in Docket No. ER13-149 (November 28, 2012).

(HAP) from coal- and oil-fired electric utility steam generating units, pursuant to section 112(d) of the Clean Air Act.³⁶ The rule requires compliance by April 16, 2015 with the possibility of one year extensions being granted to individual generation owners.³⁷

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.³⁸ The rule implements performance standards 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 2017/2018 RPM Base Residual Auction:³⁹

- **Offer Caps.** Verified that the avoidable costs, 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 period from 2011 through 2013;
- **Minimum Offer Price Rule (MOPR).** Reviewed requests for Unit-Specific Exceptions, Competitive Entry Exemptions, and Self-Supply Exemption;

³⁶ *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).

³⁷ *Id.* at 9465.

³⁸ N.J.A.C. § 7:27-19.

³⁹ 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 Demand Resource Factor and 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 2017/2018 RPM Base Residual Auction.

- **Mitigation 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;
- **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, 2013 or reviewed requests for alternate maximum EFORds;
- **Clearing Prices.** Verified that the auction clearing prices were accurate, based on submitted offers,⁴⁰ the Variable Resource Requirement (VRR) curves, and the Demand Resource Constraints;
- **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 2, all participants in the RTO and PSEG RPM markets failed the TPS test.⁴¹ 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 39 Generation Capacity Resources, including 6,827.0 MW in the 2017/2018 RPM Base Residual Auction. 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

⁴⁰ Attachment A reviews why the MMU calculation of auction outcomes differs slightly from PJM's calculation of auction outcomes.

⁴¹ See the *2013 State of the Market Report for PJM* (March 13, 2014), Volume II, Section 2, "Energy Market," and the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

RTO cost-based clearing price.⁴² 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 cost-based clearing price for the constrained LDA. The relevant demand consists of the incremental MW needed in the LDA to relieve the constraint.

Table 2 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 (RSI₃). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The TPS test uses three pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.⁴³

Table 2 RSI Results: 2017/2018 RPM Base Residual Auction⁴⁴

	RSI _{1 1.05}	RSI ₃	Total Participants	Failed RSI ₃ Participants
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1

Offer Caps

The defined Generation Capacity Resource owners were required to submit ACR or opportunity cost data to the MMU by 120 days prior to the 2017/2018 RPM Base

⁴² Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

⁴³ 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.

⁴⁴ The RSI shown is the lowest RSI in the market.

Residual Auction.⁴⁵ 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.⁴⁶ For RPM Base Residual Auctions, offer caps are defined as avoidable costs less PJM market revenues or opportunity costs.

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.⁴⁷ 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. 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.⁴⁸

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

The MMU calculated offer caps for 531 generation resources, of which 400 were based on the technology specific default (proxy) ACR values.⁴⁹ No generation resources elected

⁴⁵ 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 (November 28, 2012).

⁴⁶ OATT Attachment DD § 6.5.

⁴⁷ OATT Attachment DD § 6.8 (b).

⁴⁸ OATT Attachment DD § 6.8 (a).

⁴⁹ There were 31 generation resources that had uncapped planned updates along with ACR based offer caps calculated for the existing portion.

to use the retirement ACR in the 2017/2018 BRA. The default ACR values for the 2017/2018 Delivery Year were calculated by applying the applicable annual rate of change in the Handy-Whitman Index value to update the base values through 2013/2014 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 2014/2015 through 2016/2017 prior to estimating the default ACR values for the 2017/2018 Delivery Year.⁵⁰

Unit-specific offer caps were calculated for 126 generation resources (10.5 percent) including 122 generation resources (10.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and four generation resources (0.3 percent) without an APIR component. Owners submitted unit-specific cost data, the MMU calculated net revenue data for these units, and the MMU calculated the unit-specific offer caps based on that data. Of the 1,202 generation resources offered, five generation resources had opportunity cost based offer caps, 28 Planned Generation Capacity Resources had uncapped offers, 31 generation resources had uncapped planned uprates plus default ACR based offer caps calculated for the existing portion of the units, six generation resources had uncapped planned uprates plus price taker status for the existing portion of the units, while the remaining 637 generation resources were price takers.⁵¹

As shown in Table 4, the weighted average gross ACR for units with APIR (\$413.87 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR (\$256.02 per MW-day) increased from the 2016/2017 BRA values of \$352.84 per MW-day and \$180.23 per MW-day, due primarily to higher weighted average gross ACRs for combined cycle resources, combustion turbine resources, coal fired resources, and resources in the other category (diesel, pumped storage, hydro, and nuclear) and lower weighted-average net revenues.

⁵⁰ 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).

⁵¹ 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.

The APIR component added an average of \$217.84 per MW-day to the ACR value of the APIR units compared to \$191.19 per MW-day in the 2016/2017 BRA.^{52 53} The highest APIR for a technology (\$281.82 per MW-day) was for coal fired resources. The maximum APIR effect (\$863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Offer caps for units without an APIR component, including units for which the default value was selected, increased from \$16.07 per MW-day to \$36.87 per MW-day due primarily to lower weighted-average net revenues for units without an APIR component.⁵⁴

Table 3 ACR statistics: 2017/2018 RPM Base Residual Auction

Offer Cap/Mitigation Type	Number of Generation Resources Offered	Percent of Generation Resources Offered
Default ACR	369	30.7%
ACR data input (APIR)	122	10.1%
ACR data input (non-APIR)	4	0.3%
Opportunity cost	5	0.4%
Default ACR and opportunity cost	0	0.0%
Uncapped planned uprates and default ACR	31	2.6%
Uncapped planned uprates and opportunity cost	0	0.0%
Uncapped planned uprates and price taker	6	0.5%
Uncapped planned generation resources	28	2.3%
Existing generation resources as price takers	637	53.0%
Total Generation Capacity Resources offered	1,202	100.0%

⁵² The net revenue offset for an individual unit could exceed the corresponding ACR. In that case, the offer cap would be zero.

⁵³ The 122 resources which had an APIR component submitted \$2.8 billion for capital projects associated with 27,528.8 MW of UCAP.

⁵⁴ The default ACR values include no APIR compared to \$1.39 per MW-day in the 2016/2017 BRA.

Table 4 APIR statistics: 2017/2018 RPM Base Residual Auction^{55 56 57}

	Weighted-Average (\$ per MW-day UCAP)					Total
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Coal Fired	Other	
Non-APIR units						
ACR	\$36.92	\$31.52	\$84.84	\$182.60	\$47.54	\$94.78
Net revenues	\$121.99	\$51.56	\$13.98	\$116.61	\$158.64	\$92.26
Offer caps	\$2.17	\$9.90	\$71.43	\$70.61	\$8.28	\$36.87
APIR units						
ACR	\$136.06	\$97.45	\$180.36	\$440.80	\$554.65	\$413.87
Net revenues	\$0.00	\$1.84	\$42.70	\$92.18	\$382.31	\$137.71
Offer caps	\$136.06	\$95.61	\$137.66	\$319.61	\$163.77	\$256.02
APIR	\$95.80	\$55.48	\$92.23	\$281.82	\$128.37	\$217.84
Maximum APIR effect						\$863.76

Generation Capacity Resource Changes

As shown in Table 3, offers were submitted for 1,202 generation resources in the 2017/2018 RPM Base Residual Auction compared to 1,199 generation resources offered in the 2016/2017 RPM Base Residual Auction, or a net increase of three generation resources. This was a result of 51 additional generation resources offered offset by 48 fewer generation resources offered.

The 51 additional generation resources offered consisted of 32 new resources (5,103.3 MW), six repowered resources (941.6 MW), four resources that were excused and not offered in the 2016/2017 BRA (384.6 MW), three additional resources imported (714.1

⁵⁵ 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.

⁵⁶ For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.

⁵⁷ 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 prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

MW), three resources that were previously entirely FRR committed (164.0 MW), two additional resources resulting from the disaggregation of RPM resources, and one reactivated resource (84.1 MW).⁵⁸

The 32 new Generation Capacity Resources consisted of 15 solar resources (27.0 MW), nine diesel resources (122.5 MW), six combined cycle resources (4,825.4 MW), one CT resource (122.7 MW), and one hydro resource (5.7 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW).

The 48 fewer generation resources offered consisted of 21 external resources not offered (2,630.4 MW), 18 deactivated resources (3,018.7 MW), three Planned Generation Capacity Resources not offered (1,171.7 MW), three resources excused from offering for reasons other than retirement (554.9 MW), two additional resources committed fully to FRR (168.3MW), and one resource that is no longer a PJM capacity resource (1.7 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2016/2017 BRA: 24 CT resources (964.4 MW) and 21 steam resources (2,716.2 MW). Table 5 shows Generation Capacity Resources for which deactivation requests have been submitted which affected supply between the 2016/2017 BRA and the 2017/2018 BRA.

⁵⁸ Unless otherwise specified, all volumes and prices are in terms of UCAP.

Table 5 Generation Capacity Resource Deactivations

Resource Name	LDA	ICAP (MW)	Date Deactivation Notice Submitted	Projected or Actual Deactivation Date
PINEY CREEK NUG	MAAC	31.0	25-Jun-13	12-Apr-13
KOPPERS COMPANY	PPL	8.0	01-Jul-13	30-Sep-13
HATFIELD 1	RTO	530.0	09-Jul-13	09-Oct-13
HATFIELD 2	RTO	530.0	09-Jul-13	09-Oct-13
HATFIELD 3	RTO	530.0	09-Jul-13	09-Oct-13
MITCHELL 2 APS	RTO	82.0	09-Jul-13	09-Oct-13
MITCHELL 3 APS	RTO	277.0	09-Jul-13	09-Oct-13
MUSKINGUM RIVER 5	RTO	578.0	11-Oct-13	01-Jun-15
SUNBURY 3	PPL	81.0	17-Oct-13	18-Jul-14
SUNBURY 1	PPL	69.0	07-Nov-13	18-Jul-14
SUNBURY 2	PPL	69.0	07-Nov-13	18-Jul-14
SUNBURY 4	PPL	128.0	07-Nov-13	18-Jul-14
AES BEAVER	RTO	124.0	14-Nov-13	01-Jun-17
RIVERSIDE 4	SWMAAC	74.0	30-Nov-13	01-Jun-15
MCKEE 1	DPL South	17.0	19-Feb-14	31-May-17
MCKEE 2	DPL South	17.0	19-Feb-14	31-May-17
DALE 3	RTO	74.0	27-Mar-14	16-Apr-15
DALE 4	RTO	75.0	27-Mar-14	16-Apr-15

RTO Market Results

Total Offers

Table 6 shows total RTO offer data for the 2017/2018 RPM Base Residual Auction. All MW values stated in the RTO section include all nested LDAs.^{59 60} As shown in Table 8, total internal RTO unforced capacity (UCAP) decreased 7,225.8 MW (3.6 percent) from 200,848.1 MW in the 2016/2017 RPM BRA to 193,622.3 MW.⁶¹

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

⁵⁹ 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.

⁶⁰ Maps of the LDAs can be found in the *2013 State of the Market Report for PJM*, Appendix A, "PJM Geography."

⁶¹ The maximum capacity within a coupled Demand Resource group was included in the internal capacity values and capacity changes reported.

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 7,225.8 MW decrease in internal capacity was a result of net generation capacity modifications (cap mods) (-1,738.1 MW), net DR capacity changes (-3,472.4 MW), net EE modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-7.1 MW).⁶²

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 2017/2018 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.⁶³ 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.⁶⁴ Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit. Capacity, 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.

⁶² 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). For the 2016/2017 BRA, this conversion factor was $0.955 \times 1.0902 = 1.0411$. For the 2017/2018 BRA, this factor was $.953 \times 1.0916 = 1.0403$. The DR Factor is designed to reflect the difference in losses that occur on the distribution system between the meter where demand is measured and the transmission system. The FPR multiplier is designed to recognize the fact that when demand is reduced by one MW, the system does not need to procure that MW or the associated reserve. See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 6, Section B. See also PJM. "Manual 20: PJM Resource Adequacy Analysis," Revision 05 (February 1, 2013), p. 13-15.

⁶³ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9.

⁶⁴ 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."

After accounting for FRR committed resources and for imports, total RPM capacity was 184,616.0 MW compared to 194,324.1 MW in the 2016/2017 RPM Base Residual Auction.⁶⁵ FRR volumes increased by 395.6 MW, and imports decreased by 2,086.7 MW. Of the 5,854.8 MW of imports, 910.1 MW were committed to an FRR capacity plan and 4,944.7 MW were offered in the auction, of which 4,525.5 MW cleared. Of the cleared imports, 2,624.3 MW (58.0 percent) were from MISO. RPM capacity was reduced by exports of 1,194.5 MW, a decrease of 17.1 MW from the 2016/2017 RPM Base Residual Auction. Of total exports, 651.5 MW (54.5 percent) were to the NYISO and 543.0 MW (45.5 percent) were to MISO.

In addition, RPM capacity was reduced by 715.1 MW of Planned Generation Capacity Resources which were not subject to the RPM must offer requirement and by 1,939.1 MW which were excused from the RPM must offer requirement, a decrease of 1,681.5 MW from the 2016/2017 RPM Base Residual Auction. The excused Existing Generation Capacity Resources were the result of plans for retirement (1,387.9 MW), significant physical operational restrictions (22.0 MW), and 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 (529.2 MW).⁶⁶ Subtracting 838.0 MW of FRR optional volumes not offered, a decrease of 1,387.4 MW from the 2016/2017 RPM Base Residual Auction, and 1,090.8 MW of DR and EE not offered, resulted in 178,838.5 MW that were available to be offered in the RPM Auction, a decrease of 5,541.5 MW from the 2016/2017 RPM Base Residual Auction.⁶⁷ ⁶⁸ After accounting for the above, 0.0 MW were not offered in the RPM Auction.

⁶⁵ 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.

⁶⁶ See OATT Attachment M-Appendix § II.C.4 for the reasons to qualify for an exception to the RPM must offer requirement.

⁶⁷ FRR entities are allowed to offer in the RPM Auction excess volumes above their FRR quantities, subject to a sales cap amount. The 838.0 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.

⁶⁸ Unoffered DR and EE MW include PJM approved DR plans and EE modifications that were not offered in the auction.

Offered MW decreased 5,541.5 MW from 184,380.0 MW to 178,838.5 MW, while the overall RTO Reliability Requirement adjusted for FRR obligations, from which the demand curve is developed, decreased 1,120.4 MW from 166,127.5 MW to 165,007.1 MW.⁶⁹ 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.⁷⁰ The 1,120.4 MW decrease in the RTO Reliability Requirement adjusted for FRR obligations from the 2016/2017 RPM Base Residual Auction was a result of a 787.1 MW decrease in the RTO Reliability Requirement not adjusted for FRR and a 333.3 MW increase in the FRR obligation, shifting the RTO market demand curve to the left. The forecast peak load expressed in terms of installed capacity decreased 933.2 MW from the 2016/2017 RPM Base Residual Auction to 164,478.8 MW. The 787.1 MW decrease in the RTO Reliability Requirement was a result of a 1,017.4 MW decrease in the forecast peak load in UCAP terms holding the FPR constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in the FPR.

Demand 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.

The Limited Resource Constraint was a binding constraint for the RTO in the 2017/2018 BRA. As shown in Figure 1, the resource clearing price for Annual and Extended Summer Resources for the RTO was \$120.00 per MW-day.

⁶⁹ The maximum capacity within a coupled Demand Resource group was included in the offered capacity values reported.

⁷⁰ PJM. "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 4.1.

Clearing Results

The Net Load Price that load serving entities (LSEs) will pay is equal to the Final Zonal Capacity Price less the final Capacity Transfer Rights (CTR) credit rate.⁷¹ As shown in Table 6, the preliminary Net Load Price is \$119.81 per MW-day in the RTO.

As shown in Table 6, the cleared and make-whole MW of 167,068.9 for the entire RTO, which represented a reserve margin of 20.1 percent not considering FRR load, resulted in net excess of 6,187.0 MW over the reliability requirement of 165,007.1 MW (Installed Reserve Margin (IRM) of 15.7 percent).^{72 73} Net excess decreased 998.4 MW from the net excess of 7,815.4 MW in the 2016/2017 RPM Base Residual Auction. As shown in Figure 1, the downward sloping VRR demand curve resulted in a clearing price for Extended Summer and Annual Resources of \$120.00 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.⁷⁴ 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.⁷⁵ The market results in the 2017/2018 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

⁷¹ Effective with the 2012/2013 Delivery Year, Final Zonal Capacity Prices and the final CTR credit rate are determined after the final Incremental Auction.

⁷² 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 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

⁷³ The IRM increased from 15.6 percent in the 2016/2017 RPM Base Residual Auction to 15.7 percent in the 2017/2018 RPM Base Residual Auction.

⁷⁴ OATT Attachment DD § 5.14 (b).

⁷⁵ OATT Attachment DD § 5.12 (a).

Price Adjustment (NEPA) or Multi-Year Pricing Option.^{76 77} In the two subsequent BRAs, if a qualifying resource does not clear, the process specified in the Tariff is triggered, and the resource is awarded a make-whole payment.⁷⁸ The market results in the 2017/2018 BRA did not include make-whole MW or payments related to NEPA or Multi-Year Pricing Option.

Table 9 shows cleared MW by zone and fuel source. Of the 166,204.8 MW offered for generation resources, 154,690.0 MW cleared (93.1 percent). Of the 167,003.7 cleared MW in the entire RTO, 26,142.8 MW (15.7 percent) cleared in Dominion, followed by 22,551.0 MW (13.5 percent) in ComEd and 15,880.0 MW (9.5 percent) in AEP. Of the 154,690.0 cleared MW for generation resources in the entire RTO, 62,694.4 MW (40.5 percent) were gas resources, followed by 47,442.8 MW (30.7 percent) from coal resources and 26,401.0 MW (17.1 percent) from nuclear resources.

The 11,769.6 MW uncleared MW in the entire RTO were the result of offer prices which exceeded the clearing prices. Of the 11,769.6 uncleared MW in the entire RTO, 1.1 MW were EE offers, 318.7 MW were DR offers, and the remaining 11,449.8 MW were generation offers. Table 10 presents details on the generation offers that did not clear. Of the 11,449.8 MW of uncleared generation offers, 4,872.3 MW (42.6 percent) were for generation resources greater than 40 years old, and 6,577.5 MW (57.4 percent) were for generation resources less than or equal to 40 years old. Of the 11,449.8 MW of uncleared offers for generation resources, 4,245.6 MW were offers for resources including costs associated with environmental regulation compliance that were not previously included in APIR.

Table 11 shows the auction results for the prior two Delivery Years for the generation resources that did not clear some or all MW in the 2017/2018 BRA. Of the 47 generation resources that did not clear 11,449.8 MW in the 2017/2018 BRA, 12 of those generation resources did not clear 2,957.3 MW in RPM Auctions for the 2016/2017 Delivery Year. Of those 12 generation resources that did not clear MW in RPM Auctions for the 2017/2018 and 2016/2017 Delivery Years, five of those generation resources did not clear 854.0 MW in RPM Auctions for the 2015/2016 Delivery Year. Thus, 2,957.3 MW of capacity did not clear in two sequential auctions, but only 854.0 MW did not clear in three sequential auctions.

⁷⁶ OATT Attachment DD § 5.14 (c) (2).

⁷⁷ OATT Attachment DD § 6.8 (a).

⁷⁸ OATT Attachment DD § 5.14 (c) (2) (ii).

Constraints in RPM Markets: CETO/CETL

Since the ability to import energy and capacity in LDAs may be limited by the existing transmission capability, a load deliverability analysis is conducted for each LDA.⁷⁹ 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.⁸⁰

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 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 the above three tests.⁸¹ In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM

⁷⁹ PJM. "Manual 14B: PJM Region Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods," Revision 27 (April 23, 2014), p. 57. Manual 14B indicates that all "electrically cohesive load areas" are tested.

⁸⁰ PJM. "Manual 18: PJM Capacity Market," Revision 23 (June 1, 2014), p. 10.

⁸¹ 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.

finds that “such is required to achieve an acceptable level of reliability.”⁸² 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.

Table 12 shows the CETL and CETO values used in the 2017/2018 study compared to the 2016/2017 values. The ComEd, BGE, and PPL LDAs were modeled for the first time in the 2017/2018 BRA. None of the CETL values for previously modeled LDAs changed significantly with the exception of Pepco. The Pepco CETL decreased due to expected generation deactivations.

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 on total market revenues depends on the relative sizes of the various markets as well as the shapes of the supply and demand curves in the various markets.

There was one locationally binding constraint in the 2017/2018 BRA which resulted in demand clearing in a locationally constrained LDA which did not clear in the RTO market. 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 graphs 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.

Composition of the Steeply Sloped Portion of the Supply Curve

Table 13 shows the composition of the offers on the steeply sloped portion of the total RTO supply curve from \$35.00 per MW-day up to and including the highest offer of

⁸² OATT Attachment DD § 5.10 (a) (ii).

\$821.29 per MW-day. Offers for DR and EE resources were 13.1 percent of the offers greater than \$35.00 per MW-day. Offers for coal fired units made up 44.6 percent of the offers greater than \$35.00 per MW-day.

Short-Term Resource Procurement Target (2.5 Percent Shift in Demand Curve)

Effective for the 2012/2013 Delivery Year, ILR was eliminated. Prior to that, PJM subtracted the ILR forecast from the reliability requirement. Under the current rules, application of the Short-Term Resource Procurement Target means that 2.5 percent of the reliability requirement is removed from the demand curve (VRR curve). The stated rationale is that this provides for short lead time resource procurement in Incremental Auctions for the given delivery year. For the 2017/2018 BRA, the 2.5 percent reduction resulted in the removal of 4,125.2 MW from the RTO demand curve. For comparison purposes, in the 2011/2012 BRA, removal of the ILR forecast from the reliability requirement resulted in a reduction in demand of 1,593.8 MW, or 1.2 percent of the reliability requirement of 130,658.7 MW.⁸³

Table 14 shows the results if the VRR curves had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to \$145.02 per MW-day, and the clearing quantity would have stayed the same at 2,322.1 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to \$157.80 per MW-day, and the clearing quantity would have increased to 168,040.4 MW. The PSEG clearing price for Limited Resources would have increased to \$207.22 per MW-day, and the clearing quantity would have decreased slightly to 175.4 MW. The PSEG clearing price for Extended Summer and Annual Resources would have increased to \$220.00 per MW-day, and the clearing quantity would have increased to 6,213.7 MW. The PPL clearing price for Limited Resources would have increased to \$75.00 per MW-day, and the clearing quantity would have increased to 63.4 MW. The PPL clearing price for Extended Summer Resources would have increased to \$87.78 per MW-day, and the clearing quantity would have decreased to 161.6 MW. The PPL clearing price for Annual Resources would have increased to \$157.80 per MW-day, and the clearing quantity would have increased to 10,421.5 MW.

⁸³ These results were also reported in: *The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised*, Monitoring Analytics, LLC (August 26, 2014) <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf>

The conclusion is that the removal of 2.5 percent of demand significantly reduced the clearing prices and quantities for all the RPM LDA markets. The clearing quantities of Annual Resources, including generation and Annual DR, were reduced as a result of the 2.5 percent demand reduction.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,947,329,539, an increase of \$2,435,099,909, or 32.4 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target resulted in a 24.5 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the 2.5 percent reduction in demand.

Table 15 shows the results if the VRR curves and Demand Resource Constraints had not been reduced by the Short-Term Resource Procurement Target and everything else had remained the same. All binding constraints would have remained the same, except that the RTO Limited Resource Constraint would not have been binding, and the PPL Sub-Annual Resource Constraint would not have been binding. The RTO clearing price for Limited, Extended Summer, and Annual Resources would have increased to \$157.80 per MW-day, and the clearing quantity would have increased to 170,362.5 MW. The PSEG clearing price for Limited, Extended Summer, and Annual Resources would have increased to \$220.00 per MW-day, and the clearing quantity would have increased to 6,389.1 MW. The PPL clearing price for Limited, Extended Summer, and Annual Resources would have increased to \$157.80 per MW-day, and the clearing quantity would have increased to 10,714.4 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the VRR curves and Demand Resource Constraints had not been reduced by the Short-Term Resource Procurement Target, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,967,834,187, an increase of \$2,455,604,557, or 32.7 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target resulted in a 24.6 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the 2.5 percent reduction of demand.

The MMU recommends that the use of the 2.5 percent demand adjustment be terminated immediately.⁸⁴ The 2.5 percent demand reduction inefficiently suppresses clearing prices and is a barrier to entry in the capacity market for both new generation capacity and new DR capacity. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined. The proposal to eliminate the Short Term Resource Procurement Target is not counter to the interests of DR. Most DR clears in the BRA where prices have been substantially higher than in the Incremental Auctions. Price suppression is a barrier to the entry of new Demand Resources in exactly the same way that it is a barrier to the entry of new generation resources. In the 2017/2018 BRA, the result of reducing demand by 2.5 percent was to reduce prices in the eastern part of PJM and to reduce the quantity of capacity purchased in the eastern part of PJM. The result was also to significantly reduce the clearing price for the RTO market and reducing total payments to capacity by a significant amount. The 2.5 percent offset was added to permit DR to clear in Incremental Auctions. 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.

Demand Side Resources in RPM

There are two categories of demand side products included in the RPM market design for the 2017/2018 BRA.^{85 86}

⁸⁴ See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

⁸⁵ 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.⁸⁷ 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.⁸⁸

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products included in the RPM market design:^{89 90}

- **Annual DR.** 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.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year

⁸⁶ 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.

⁸⁷ "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section M.

⁸⁸ Letter Order in Docket No. ER10-366-000 (January 22, 2010).

⁸⁹ 134 FERC ¶ 61,066 (2011).

⁹⁰ "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1. <<http://www.pjm.com/~media/documents/agreements/raa.ashx>>

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.

Table 16 shows offered and cleared capacity from Demand Resources and Energy Efficiency Resources in the 2017/2018 RPM Base Residual Auction compared to the 2016/2017 RPM Base Residual Auction. Offers for DR decreased from 14,507.2 MW in the 2016/2017 BRA to 11,293.7 MW in the 2017/2018 BRA, a decrease of 3,213.5 or 22.2 percent.

Table 17 shows offered and cleared MW for Demand Resources by LDA and offer/product type in the 2017/2018 RPM Base Residual Auction. Of the 3,297.2 MW of non-coupled DR offers, 1,015.8 MW were for the Limited DR product. Of the possible DR coupling scenarios, the most frequently used was the Annual, Extended Summer, and Limited DR coupling group, with from 3,000 to 5,500 MW of DR offered this way. The fact that most offers were coupled provides evidence that suppliers are willing to offer a DR product that is more comparable to generation resources in that it does not have such significant limitations on availability and that they will offer it at a higher price, reflecting the fact that such a product has higher costs.

Table 18 shows the weighted average prices for DR by LDA and offer/product type. As would be expected, given their relative values, for the coupled DR offers, the offers for Annual DR were greater than the offers for Extended Summer DR which were greater than the offers for Limited DR. In addition, 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.

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.

Impact of Limited and Extended Summer DR Product Types

Effective for the 2014/2015 Delivery Year, the RPM market design incorporates Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type. Each DR product type is subject to a defined period of availability, maximum number of interruptions, and maximum duration of interruptions. The Limited DR and the Extended Summer DR product types are both inferior to Generation Capacity Resources, because the obligation to deliver associated with both product types is inferior to the obligation to deliver associated with Generation Capacity Resources. Generation resources are obligated to provide capacity every hour of the year if called.

Table 19 shows the results if only generation, Annual DR, and Energy Efficiency (EE) resources were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. All offers for Extended Summer and Limited DR products, including those within coupled DR offers, were excluded from supply. All offers for Annual DR were included in supply, including those in non-coupled and coupled DR offers. All import limit binding constraints would have remained the same. The RTO clearing price would have increased to \$157.80 per MW-day, and the clearing quantity would have decreased to 166,237.1 MW. The PSEG clearing price would have increased to \$220.00 per MW-day, and the clearing quantity would have decreased to 6,103.4 MW. The PPL clearing price would have increased to \$157.80 per MW-day, and the clearing quantity would have increased to 10,543.8 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,738,222,922, an increase of \$2,225,993,292, or 29.6 percent, compared to the actual results. From another perspective, the inclusion of the Limited and Extended Summer DR products resulted in a 22.9 percent reduction in RPM revenues for the 2017/2018 Base Residual Auction compared to what RPM revenues would have been without the Limited and Extended Summer DR products.

While competition from demand side resources improves the functioning of the market, that is not the result if the demand side resources are not comparable to other capacity resources. The purpose of demand side participation in RPM is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers providing Limited DR only have to agree to interrupt ten times per year for a maximum of six hours per interruption represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year or a

maximum of 60 hours per year or only during defined summer hours. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM Auctions. This limitation means that the demand side resources sold in the RPM Auctions are of less value than generation capacity. As a result, demand side resources could make lower offers than they would if they offered a comparable resource.

Given the significant impact of demand side resources on the RPM market outcomes, the MMU recommends that the definition of demand side resources be modified in order to ensure that such resources provide the same value in the capacity market as generation resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. As an example, if a single demand side site could not interrupt more than ten times per year, a Curtailment Service Provider (CSP) could bundle multiple demand sites to provide unlimited interruptions. The cost of providing bundled sites would be expected to be greater than a single site and the offer price of such resources would also be expected to be greater. In addition, the definition of the Annual DR product should be modified to eliminate all limitations on its obligation to perform. Such modifications would help ensure that demand side resources contribute to the competitiveness of capacity markets rather than suppressing the price below the competitive level.

Impact of Short-Term Resource Procurement Target and Limited and Extended Summer DR Product Types

Table 20 shows the results if the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. All import limit binding constraints would have remained the same. The RTO clearing price would have increased to \$173.76 per MW-day, and the clearing quantity would have increased to 170,037.8 MW. The PSEG clearing price would have increased to \$225.00 per MW-day, and the clearing quantity would have increased to 6,381.6 MW. The PPL clearing price would have increased to \$173.76 per MW-day, and the clearing quantity would have increased to 10,546.7 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the VRR curves had not been reduced by the Short-Term Resource Procurement Target and only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$10,932,522,889, an increase of \$3,420,293,259, or 45.5 percent, compared to the actual results. From another perspective, the use of the Short-Term Resource Procurement Target together with the inclusion of the Limited and Extended Summer DR products

resulted in a 31.3 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without the Short-Term Resource Procurement Target or the Limited and Extended Summer DR products.

Impact of All DR

Table 21 shows the results if there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same. The PSEG import limit would not have been binding. The RTO clearing price would have increased to \$282.16 per MW-day, and the clearing quantity would have decreased to 163,713.2 MW. The PSEG clearing price would have increased to \$282.16 per MW-day, and the clearing quantity would have increased to 6,177.1 MW. The PPL clearing price would have increased to \$282.16 per MW-day, and the clearing quantity would have increased to 9,879.3 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$16,859,658,203, an increase of \$9,347,428,573, or 124.4 percent, compared to the actual results. From another perspective, the inclusion of Demand Resources and Energy Efficiency resources resulted in a 55.4 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to what RPM revenues would have been without any Demand Resources or Energy Efficiency resources.

These impacts combine the impact of Annual DR with the price suppressing impacts of the Limited and Extended Summer DR products.

Impact of Annual DR

The inclusion of sell offers for Annual DR and 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 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If only generation, Annual DR, and EE were offered in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$9,738,222,922. If there were no offers for DR or EE in the 2017/2018 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$16,859,658,203, an increase of \$7,121,435,281, or 73.1 percent, compared to the results with only generation, Annual DR, and EE. The inclusion of sell offers for Annual DR and EE resulted in a 42.2 percent reduction in RPM revenues for the 2017/2018 RPM Base Residual Auction compared to the revenues without any demand side products.

This is the best measure of the competitive impact of demand side products on the RPM market. The Annual DR product definition is the only one relatively close to consistent with being a capacity resource. Assuming that the DR meets appropriate measurement and verification standards and that the DR was offered with the intention of providing physical resources, competition from the Annual DR product and Energy Efficiency resources resulted in a 42.2 percent reduction of payments for capacity. This demonstrates that Annual DR together with 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 Annual DR product, DR has a significant and appropriate competitive impact on capacity market outcomes. As in prior BRAs, Extended Summer and Limited DR products also had a significant impact in the 2017/2018 BRA, but those impacts resulted from badly defined and inferior products.

Impact of Environmental Regulation Compliance

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.⁹¹ The rule requires compliance by April 16, 2015.⁹²

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.⁹³ The rule implements performance standards on May 1, 2015, just prior to the commencement of the 2015/2016 Delivery Year.

Table 22 shows the results if the APIR associated with environmental regulation compliance, which were not previously submitted, were removed and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to \$118.06 per MW-day, and the clearing quantity would have remained the same at 2,322.1 MW. The RTO

⁹¹ *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).

⁹² *Id.* at 9465.

⁹³ N.J.A.C. § 7:27-19.

clearing price for Extended Summer and Annual Resources would have remained the same at \$120.00 per MW-day, and the clearing quantity would have decreased slightly to 164,653.8 MW. The PSEG clearing price for Limited Resources would have increased to \$213.06 per MW-day, and the clearing quantity would have increased slightly to 177.7 MW. The PSEG clearing price and quantity for Extended Summer and Annual Resources would have remained the same, with some shifting between product types. The PPL clearing prices and quantities for Limited and Annual Resources would have remained the same. The PPL clearing price for Extended Summer Resources would have decreased to \$41.94 per MW-day, and the clearing quantity would have remained the same at 183.3 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If the APIR associated with the pending environmental regulations which were not previously submitted were removed, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$7,531,360,041, an increase of \$19,130,411, or 0.3 percent, compared to the total based on actual results. From another perspective, the impact of including environmental compliance costs in APIR was to decrease total market revenues by \$19,130,411, or 0.3 percent.

Capacity Imports

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.^{94 95} Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORD; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

⁹⁴ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 9 & 10.

⁹⁵ See PJM. "Manual 18: PJM Capacity Market", Revision 24 (July 31, 2014), pp. 44-46 & p. 65-66.

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.⁹⁶

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.⁹⁷ ⁹⁸ 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.⁹⁹ 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.¹⁰⁰

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.¹⁰¹ 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

⁹⁶ OATT, Schedule 1, Section 1.10.1A.

⁹⁷ See “Reliability Assurance Agreement Among Load Serving Entities in the PJM Region”, Section 1.69A.

⁹⁸ See PJM. “Manual 18: PJM Capacity Market”, Revision 24 (July 31, 2014), pp. 47-48.

⁹⁹ 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).

¹⁰⁰ 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).

¹⁰¹ 147 FERC ¶ 61,060 (2014).

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.

Impact of Imports

Table 23 shows the results if import offers for external generation resources in the 2017/2018 RPM Base Residual Auction were reduced by 25 percent and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to \$125.42 per MW-day, and the clearing quantity would have stayed the same at 2,322.1 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to \$132.07 per MW-day, and the clearing quantity would have decreased to 164,416.5 MW. The PSEG clearing price for Limited Resources would have increased to \$208.35 per MW-day, and the clearing quantity would have remained the same at 177.5 MW. The PSEG clearing price for Extended Summer and Annual Resources would have remained the same at \$215.00 per MW-day, and the clearing quantity would have increased slightly to 5,933.5 MW. The PPL clearing price for Limited Resources would have stayed the same at \$40.00 per MW-day, and the clearing quantity would have stayed the same at 41.7 MW. The PPL clearing price for Extended Summer Resources would have decreased to \$46.65 per MW-day, and the clearing quantity would have remained the same at 183.3 MW. The PPL clearing price for Annual Resources would have increased to \$132.07 per MW-day, and the clearing quantity would have increased to 9,731.0 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If offers for external generation were reduced by 25 percent and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$8,210,054,013, an increase of \$697,824,383, or 9.3 percent, compared to the actual results. From another perspective, the impact of including 75 percent of the offers for external generation resources was to decrease total market revenues by \$697,824,383, or 8.5 percent.

Table 23 shows the results if offers for external generation resources in the 2017/2018 RPM Base Residual Auction were reduced by 75 percent and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to \$162.16 per MW-day, and the clearing quantity would have stayed the same at 2,322.1 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to \$167.17 per MW-day, and the clearing quantity would have decreased to 163,324.3 MW. The PSEG clearing price for Limited Resources would have increased to \$209.99 per MW-day, and the clearing quantity would have decreased slightly to 173.5 MW. The PSEG clearing price for Extended Summer and Annual Resources would have remained the same at \$215.00 per MW-day, and the clearing quantity would have increased slightly to 5,937.4

MW. The PPL clearing price for Limited Resources would have increased to \$75.00 per MW-day, and the clearing quantity would have increased to 63.7 MW. The PPL clearing price for Extended Summer Resources would have increased to \$80.01 per MW-day, and the clearing quantity would have decreased to 161.3 MW. The PPL clearing price for Annual Resources would have increased to \$167.17 per MW-day, and the clearing quantity would have increased to 10,424.5 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If offers for external generation were reduced by 75 percent and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$10,202,534,135, an increase of \$2,690,304,504, or 35.8 percent, compared to the actual results. From another perspective, the impact of including 25 percent of the offers for external generation resources was to decrease total market revenues by \$2,690,304,504, or 26.4 percent.

Of the 4,944.7 MW offered for external generation resources in the 2017/2018 RPM Base Residual Auction, 963.9 MW or 19.5 percent were not or did not plan to be pseudo tied. Table 23 shows the results if offers for external generation resources in the 2017/2018 RPM Base Residual Auction without pseudo ties were excluded and everything else had remained the same. All binding constraints would have remained the same. The RTO clearing price for Limited Resources would have increased to \$109.56 per MW-day, and the clearing quantity would have remained the same at 2,322.1 MW. The RTO clearing price for Extended Summer and Annual Resources would have increased to \$124.56 per MW-day, and the clearing quantity would have decreased slightly to 164,589.2 MW. The PSEG clearing price for Limited Resources would have decreased to \$200.00 per MW-day, and the clearing quantity would have increased slightly to 177.7 MW. The PSEG clearing price for Extended Summer and Annual Resources would have remained the same at \$215.00 per MW-day, and the clearing quantity would have remained the same at 5,933.2 MW. The PPL clearing price for Limited Resources would have remained the same at \$40.00 per MW-day, and the clearing quantity would have remained the same at 41.7 MW. The PPL clearing price for Extended Summer Resources would have increased to \$55.00 per MW-day, and the clearing quantity would have remained the same at 183.3 MW. The PPL clearing price for Annual Resources would have increased to \$124.56 per MW-day, and the clearing quantity would have increased to 9,430.4 MW.

Based on actual auction clearing prices and quantities and make-whole MW, total RPM market revenues for the 2017/2018 RPM Base Residual Auction were \$7,512,229,630. If offers for external generation resources without pseudo ties were excluded and everything else had remained the same, total RPM market revenues for the 2017/2018 RPM Base Residual Auction would have been \$7,785,489,989, an increase of \$273,260,359, or 3.6 percent, compared to the actual results. From another perspective,

the impact of including external generation resources without pseudo ties was to decrease total market revenues by \$273,260,359, or 3.5 percent.

Tables and Figures for RTO Market

Table 6 RTO offer statistics: 2017/2018 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	189,798.5	179,341.6		
DR capacity	12,307.9	12,803.2		
EE capacity	1,421.8	1,477.5		
Total internal RTO capacity	203,528.2	193,622.3		
FRR	(15,776.1)	(14,861.1)		
Imports	6,300.9	5,854.8		
RPM capacity	194,053.0	184,616.0		
Exports	(1,223.2)	(1,194.5)		
FRR optional	(1,308.1)	(838.0)		
Excused Existing Generation Capacity Resources	(2,251.2)	(1,939.1)		
Unoffered Planned Generation Capacity Resources	(744.8)	(715.1)		
Unoffered DR and EE	(1,050.8)	(1,090.8)		
Available	187,474.9	178,838.5	100.0%	100.0%
Generation offered	175,329.5	166,204.8	93.5%	92.9%
DR offered	10,855.2	11,293.7	5.8%	6.3%
EE offered	1,289.0	1,340.0	0.7%	0.7%
Total offered	187,473.7	178,838.5	100.0%	100.0%
Unoffered Existing Generation Capacity Resources	1.2	0.0	0.0%	0.0%
Cleared in RTO		166,628.1		93.2%
Cleared in LDAs		375.6		0.2%
Total cleared		167,003.7		93.4%
Make-whole		65.2		0.0%
Uncleared generation		11,449.8		6.4%
Uncleared DR		318.7		0.2%
Uncleared EE		1.1		0.0%
Total uncleared		11,769.6		6.6%
Reliability requirement		165,007.1		
Total cleared plus make-whole		167,068.9		
Short-Term Resource Procurement Target		4,125.2		
Net excess/(deficit)		6,187.0		
Resource clearing price for Limited Resources (\$ per MW-day)		\$106.02		
Resource clearing price for Extended Summer Resources (\$ per MW-day)		\$120.00		
Resource clearing price for Annual Resources (\$ per MW-day)		\$120.00		
Preliminary zonal capacity price (\$ per MW-day)		\$119.81	A	
Base zonal CTR credit rate (\$ per MW-day)		\$0.00	B	
Preliminary net load price (\$ per MW-day)		\$119.81	A-B	

Table 7 Capacity modifications (ICAP): 2017/2018 RPM Base Residual Auction¹⁰²

	ICAP (MW)		
	RTO	PSEG	PPL
Generation increases	6,988.1	4.0	1,007.9
Generation decreases	(9,760.1)	(1,228.8)	(62.7)
Capacity modifications net increase/(decrease)	(2,772.0)	(1,224.8)	945.2
DR increases	6,224.9	175.4	398.1
DR decreases	(9,556.1)	(336.4)	(562.3)
DR net increase/(decrease)	(3,331.2)	(161.0)	(164.2)
EE increases	1,107.6	12.8	23.2
EE decreases	(954.3)	(8.7)	(24.2)
EE modifications increase/(decrease)	153.3	4.1	(1.0)
Net internal capacity increase/(decrease)	(5,949.9)	(1,381.7)	780.0

¹⁰² Only cap mods that had a start date on or before June 1, 2017 and DR and EE plans for the 2017/2018 RPM Base Residual Auction are included.

Table 8 Capacity modifications (UCAP): 2017/2018 RPM Base Residual Auction

	UCAP (MW)		
	RTO	PSEG	PPL
Generation increases	6,709.7	4.0	967.5
Generation decreases	(8,447.8)	(1,136.4)	(57.5)
Capacity modifications net increase/(decrease)	(1,738.1)	(1,132.4)	910.0
DR increases	6,475.9	182.2	414.0
DR decreases	(9,948.3)	(350.1)	(585.2)
DR net increase/(decrease)	(3,472.4)	(167.9)	(171.2)
EE increases	1,150.9	13.2	24.2
EE decreases	(992.0)	(8.8)	(25.2)
EE modifications increase/(decrease)	158.9	4.4	(1.0)
Net capacity/DR/EE modifications increase/(decrease)	(5,051.6)	(1,295.9)	737.8
EFORd effect	(2,167.1)	(122.1)	(236.1)
DR and EE effect	(7.1)	(0.4)	(0.3)
Net internal capacity increase/(decrease)	(7,225.8)	(1,418.4)	501.4

Table 9 Cleared MW by zone and resource type/fuel source: 2017/2018 RPM Base Residual Auction¹⁰³

Zone	Cleared UCAP (MW)										Total
	DR	EE	Coal	Gas	Hydroelectric	Nuclear	Oil	Solar	Solid Waste	Wind	
AECO	134.7	0.8	450.2	1,300.3	0.0	0.0	26.0	13.2	0.0	0.0	1,925.2
AEP	1,426.1	136.3	6,309.5	7,725.7	90.0	0.0	0.0	0.0	0.0	192.4	15,880.0
AP	928.9	10.3	4,836.6	2,351.1	134.8	0.0	0.0	12.9	0.0	116.4	8,391.0
ATSI	1,020.2	142.0	2,876.5	2,741.3	0.0	2,022.9	174.4	0.0	0.0	0.0	8,977.3
BGE	791.2	123.7	1,375.6	525.1	0.0	1,670.7	481.1	0.0	54.6	0.0	5,022.0
ComEd	1,478.1	583.3	4,633.0	9,014.9	0.0	6,318.8	204.4	3.4	0.0	315.1	22,551.0
DAY	209.4	49.2	2,464.2	1,328.4	106.9	0.0	45.8	0.5	0.0	0.0	4,204.4
DEOK	192.4	17.5	2,245.1	42.1	0.0	0.0	234.6	0.0	0.0	0.0	2,731.7
DLCO	161.4	10.6	526.3	204.9	0.0	1,731.6	12.6	0.0	0.0	0.0	2,647.4
Dominion	1,141.1	20.7	5,044.2	11,118.7	3,502.1	3,483.1	1,610.3	3.2	219.4	0.0	26,142.8
DPL	369.7	29.0	389.5	3,972.3	0.0	0.0	850.2	2.3	0.0	0.0	5,613.0
EKPC	140.1	0.5	1,600.4	718.1	129.6	0.0	0.0	0.0	0.0	0.0	2,588.7
External	0.0	0.0	3,568.4	635.2	290.7	12.2	0.0	0.0	0.0	19.0	4,525.5
JCPL	159.4	7.1	0.0	2,821.3	411.2	0.0	139.3	35.5	9.0	0.0	3,582.8
Met-Ed	298.9	12.8	493.3	2,022.7	18.5	794.3	218.5	0.0	75.9	0.0	3,934.9
PECO	480.0	24.8	9.0	3,310.1	1,630.9	4,555.2	1,452.2	1.0	95.8	0.0	11,559.0
PENELEC	356.8	12.9	6,245.5	1,035.1	571.5	0.0	108.5	0.0	40.4	133.3	8,504.0
Peppo	608.4	104.2	2,163.3	2,339.8	0.0	0.0	1,405.7	0.0	50.0	0.0	6,671.4
PPL	686.2	35.6	1,862.9	4,328.3	691.7	2,395.4	1,978.9	5.7	8.5	27.5	12,020.7
PSEG	388.4	17.6	349.3	5,159.0	1.7	3,416.8	0.0	38.7	156.0	0.0	9,527.5
RECO	3.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4
Total	10,974.8	1,338.9	47,442.8	62,694.4	7,579.6	26,401.0	8,942.5	116.4	709.6	803.7	167,003.7

Table 10 Uncleared generation offers by technology type and age: 2017/2018 RPM Base Residual Auction¹⁰⁴

Technology Type	Uncleared UCAP (MW)		Total
	Less Than or Equal to 40 Years Old	Greater than 40 Years Old	
Coal Fired	2,703.5	2,797.5	5,501.0
Combined cycle	1,064.6	0.0	1,064.6
Combustion turbine	391.1	127.9	519.0
Oil or gas steam	58.1	0.0	58.1
Other	2,360.2	1,946.9	4,307.1
Total	6,577.5	4,872.3	11,449.8

¹⁰³ 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, 3,416.8 MW of the 9,527.5 cleared MW in the PSEG Zone were modeled and cleared in the EMAAC LDA.

¹⁰⁴ 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 prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

Table 11 Uncleared generation resources in multiple auctions¹⁰⁵

Technology	2017/2018		2016/2017 Results for Same Set of Resources		2015/2016 Results for Same Set of Resources	
	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources	Uncleared UCAP (MW)	Number of Resources
Coal Fired	5,501.0	12	2,065.8	5	796.7	3
Combined cycle	1,064.6	3	757.0	1	0.0	0
Combustion turbine	519.0	21	76.2	4	0.0	0
Oil or gas steam	58.1	2	58.3	2	57.3	2
Other	4,307.1	9	0.0	0	0.0	0
Total	11,449.8	47	2,957.3	12	854.0	5

Table 12 PJM LDA CETL and CETO Values: 2016/2017 and 2017/2018 RPM Base Residual Auctions

LDA	2016/2017			2017/2018			Change			
	CETO	CETL	CETL to CETO Ratio	CETO	CETL	CETL to CETO Ratio	CETO MW	Percentage	CETL MW	Percentage
MAAC	5,220.0	6,495.0	124%	4,420.0	7,393.0	167%	(800.0)	(15%)	898.0	14%
EMAAC	6,140.0	8,916.0	145%	6,140.0	9,315.0	152%	0.0	0%	399.0	4%
SWMAAC	5,840.0	8,786.0	150%	5,880.0	8,053.0	137%	40.0	1%	(733.0)	(8%)
PSEG	6,450.0	6,581.0	102%	6,080.0	6,700.0	110%	(370.0)	(6%)	119.0	2%
PSEG North	2,450.0	2,936.0	120%	2,370.0	2,795.0	118%	(80.0)	(3%)	(141.0)	(5%)
DPL South	1,580.0	1,901.0	120%	1,440.0	1,904.0	132%	(140.0)	(9%)	3.0	0%
Pepco	2,730.0	6,846.0	251%	3,740.0	5,359.0	143%	1,010.0	37%	(1,487.0)	(22%)
ATSI	5,390.0	7,881.0	146%	4,970.0	8,470.0	170%	(420.0)	(8%)	589.0	7%
ATSI Cleveland	3,800.0	5,245.0	138%	3,350.0	4,940.0	147%	(450.0)	(12%)	(305.0)	(6%)
ComEd	NA	NA	NA	2,290.0	7,020.0	307%	NA	NA	NA	NA
BGE	NA	NA	NA	4,350.0	6,217.0	143%	NA	NA	NA	NA
PPL	NA	NA	NA	1,310.0	4,336.0	331%	NA	NA	NA	NA

¹⁰⁵ 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 prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

Table 13 Offers greater than \$35.00 per MW-day on total RTO supply curve: 2017/2018 RPM Base Residual Auction^{106 107}

Technology/Resource Type	Offered UCAP (MW)	Percent of Offers
Coal fired	12,325.3	44.6%
Other generation	4,307.1	15.6%
Oil or gas steam	4,198.7	15.2%
Demand Resource coupled	2,695.4	9.8%
Combined cycle	1,624.4	5.9%
Combustion turbine	1,579.1	5.7%
Demand Resource non-coupled	808.6	2.9%
Energy Efficiency Resource	105.2	0.4%
Total	27,643.8	100.0%

¹⁰⁶ For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in the offered capacity values reported.

¹⁰⁷ 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 prior versions of this table. For the 2017/2018 BRA, waste coal resources were included in the coal fired category.

Table 14 Impact of Short-Term Resource Procurement Target: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		No Short-Term Resource Procurement Target Reduction from VRR Curve	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1	\$145.02	2,322.1
	Extended Summer	\$120.00	7,163.3	\$157.80	7,288.7
	Annual	\$120.00	157,518.3	\$157.80	160,751.7
RTO Total			167,003.7		170,362.5
PSEG	Limited	\$201.02	177.5	\$207.22	175.4
	Extended Summer	\$215.00	154.8	\$220.00	157.0
	Annual	\$215.00	5,778.4	\$220.00	6,056.7
PSEG Total			6,110.7		6,389.1
PPL	Limited	\$40.00	41.7	\$75.00	63.4
	Extended Summer	\$53.98	183.3	\$87.78	161.6
	Annual	\$120.00	9,123.5	\$157.80	10,421.5
PPL Total			9,348.5		10,646.5

Table 15 Impact of Short-Term Resource Procurement Target: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		No Short-Term Resource Procurement Target Reduction	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1	\$157.80	4,476.4
	Extended Summer	\$120.00	7,163.3	\$157.80	5,339.1
	Annual	\$120.00	157,518.3	\$157.80	160,547.0
RTO Total			167,003.7		170,362.5
PSEG	Limited	\$201.02	177.5	\$220.00	201.2
	Extended Summer	\$215.00	154.8	\$220.00	130.9
	Annual	\$215.00	5,778.4	\$220.00	6,057.0
PSEG Total			6,110.7		6,389.1
PPL	Limited	\$40.00	41.7	\$157.80	350.0
	Extended Summer	\$53.98	183.3	\$157.80	79.8
	Annual	\$120.00	9,123.5	\$157.80	10,284.6
PPL Total			9,348.5		10,714.4

Table 16 DR and EE statistics by LDA: 2016/2017 and 2017/2018 RPM Base Residual Auctions¹⁰⁸

LDA	Resource Type	2016/2017 BRA			2017/2018 BRA			Offered ICAP		Change Offered UCAP		Cleared UCAP	
		Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	MW	Percentage	MW	Percentage	MW	Percentage
RTO	DR	13,932.9	14,507.2	12,408.1	10,855.2	11,293.7	10,975.0	(3,077.7)	(22.1%)	(3,213.5)	(22.2%)	(1,433.1)	(11.5%)
RTO	EE	1,112.6	1,156.8	1,117.3	1,289.0	1,340.0	1,338.9	176.4	15.9%	183.2	15.8%	221.6	19.8%
MAAC	DR	5,477.4	5,703.5	5,350.2	4,303.6	4,477.7	4,277.3	(1,173.8)	(21.4%)	(1,225.8)	(21.5%)	(1,072.9)	(20.1%)
MAAC	EE	318.5	330.9	310.1	356.0	369.6	368.5	37.5	11.8%	38.7	11.7%	58.4	18.8%
EMAAC	DR	2,069.5	2,155.0	2,006.4	1,506.6	1,567.7	1,535.6	(562.9)	(27.2%)	(587.3)	(27.3%)	(470.8)	(23.5%)
EMAAC	EE	62.1	64.1	51.2	77.7	80.4	79.3	15.6	25.1%	16.3	25.4%	28.1	54.9%
SWMAAC	DR	1,588.1	1,653.8	1,600.5	1,367.9	1,423.0	1,399.6	(220.2)	(13.9%)	(230.8)	(14.0%)	(200.9)	(12.6%)
SWMAAC	EE	200.3	208.6	208.4	219.2	227.9	227.9	18.9	9.4%	19.3	9.3%	19.5	9.4%
DPL South	DR	119.1	124.0	105.7	84.6	88.1	86.3	(34.5)	(29.0%)	(35.9)	(29.0%)	(19.4)	(18.4%)
DPL South	EE	0.7	0.7	0.6	0.8	0.8	0.8	0.1	14.3%	0.1	14.3%	0.2	33.3%
PSEG	DR	610.9	636.5	630.7	377.4	392.7	388.4	(233.5)	(38.2%)	(243.8)	(38.3%)	(242.3)	(38.4%)
PSEG	EE	14.6	14.9	11.9	18.2	18.7	17.6	3.6	24.7%	3.8	25.5%	5.7	47.9%
PSEG North	DR	218.8	228.2	226.6	149.5	155.7	151.5	(69.3)	(31.7%)	(72.5)	(31.8%)	(75.1)	(33.1%)
PSEG North	EE	4.1	4.1	3.1	3.9	3.9	3.4	(0.2)	(4.9%)	(0.2)	(4.9%)	0.3	9.7%
Pepco	DR	656.4	683.8	663.9	595.7	619.8	608.4	(60.7)	(9.2%)	(64.0)	(9.4%)	(55.5)	(8.4%)
Pepco	EE	80.3	83.7	83.5	100.2	104.2	104.2	19.9	24.8%	20.5	24.5%	20.7	24.8%
ATSI	DR	1,844.7	1,920.7	1,811.9	1,023.1	1,064.4	1,020.2	(821.6)	(44.5%)	(856.3)	(44.6%)	(791.7)	(43.7%)
ATSI	EE	191.2	198.9	196.6	136.8	142.0	142.0	(54.4)	(28.5%)	(56.9)	(28.6%)	(54.6)	(27.8%)
ATSI Cleveland	DR	473.4	492.8	468.7	290.7	302.5	290.1	(182.7)	(38.6%)	(190.3)	(38.6%)	(178.6)	(38.1%)
ATSI Cleveland	EE	50.8	52.8	52.6	34.4	35.7	35.7	(16.4)	(32.3%)	(17.1)	(32.4%)	(16.9)	(32.1%)
ComEd	DR	1,654.1	1,722.3	1,236.2	1,441.5	1,499.6	1,478.1	(212.6)	(12.9%)	(222.7)	(12.9%)	241.9	19.6%
ComEd	EE	409.9	426.7	426.7	560.7	583.3	583.3	150.8	36.8%	156.6	36.7%	156.6	36.7%
BGE	DR	931.7	970.0	936.6	772.2	803.2	791.2	(159.5)	(17.1%)	(166.8)	(17.2%)	(145.4)	(15.5%)
BGE	EE	120.0	124.9	124.9	119.0	123.7	123.7	(1.0)	(0.8%)	(1.2)	(1.0%)	(1.2)	(1.0%)
PPL	DR	994.2	1,035.1	998.2	781.2	812.7	686.4	(213.0)	(21.4%)	(222.4)	(21.5%)	(311.8)	(31.2%)
PPL	EE	35.0	36.5	30.2	34.0	35.6	35.6	(1.0)	(2.9%)	(0.9)	(2.5%)	5.4	17.9%

Table 17 Offered and cleared DR by LDA and offer/product type: 2017/2018 RPM Base Residual Auction

LDA	Offer Type	Product Type(s)	Offered UCAP (MW)			Cleared UCAP (MW)		
			Annual	Extended Summer	Limited	Annual	Extended Summer	Limited
RTO	Non-coupled	Annual	1,106.9	0.0	0.0	1,106.9	0.0	0.0
RTO	Non-coupled	Extended Summer	0.0	1,174.5	0.0	0.0	1,174.5	0.0
RTO	Non-coupled	Limited	0.0	0.0	1,015.8	0.0	0.0	980.9
RTO	Coupled	Annual and Extended Summer	1,231.2	1,402.4	0.0	94.1	1,331.6	0.0
RTO	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
RTO	Coupled	Extended Summer and Limited	0.0	671.6	726.9	0.0	243.9	470.4
RTO	Coupled	Annual, Extended Summer, and Limited	5,305.7	5,617.8	2,910.1	288.4	4,413.3	870.8
PSEG	Non-coupled	Annual	56.1	0.0	0.0	56.1	0.0	0.0
PSEG	Non-coupled	Extended Summer	0.0	48.4	0.0	0.0	48.4	0.0
PSEG	Non-coupled	Limited	0.0	0.0	74.9	0.0	0.0	74.9
PSEG	Coupled	Annual and Extended Summer	33.3	33.3	0.0	0.0	33.3	0.0
PSEG	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
PSEG	Coupled	Extended Summer and Limited	0.0	17.9	17.9	0.0	0.7	17.2
PSEG	Coupled	Annual, Extended Summer, and Limited	136.8	154.3	112.5	0.0	72.4	85.4
PPL	Non-coupled	Annual	102.0	0.0	0.0	102.0	0.0	0.0
PPL	Non-coupled	Extended Summer	0.0	35.0	0.0	0.0	35.0	0.0
PPL	Non-coupled	Limited	0.0	0.0	25.5	0.0	0.0	6.5
PPL	Coupled	Annual and Extended Summer	70.8	70.8	0.0	70.8	0.0	0.0
PPL	Coupled	Annual and Limited	0.0	0.0	0.0	0.0	0.0	0.0
PPL	Coupled	Extended Summer and Limited	0.0	21.8	21.8	0.0	0.0	9.2
PPL	Coupled	Annual, Extended Summer, and Limited	469.4	514.7	409.8	288.4	148.3	26.0

¹⁰⁸ The maximum capacity within a coupled Demand Resource group was assumed in the offered capacity values reported.

Table 18 Weighted-average sell offer prices for DR by LDA and offer/product type: 2017/2018 RPM Base Residual Auction

LDA	Offer Type	Product Type(s)	Weighted-Average (\$ per MW-day UCAP)		
			Annual	Extended Summer	Limited
RTO	Non-coupled	Annual	\$31.06		
RTO	Non-coupled	Extended Summer		\$16.19	
RTO	Non-coupled	Limited			\$24.54
RTO	Coupled	Annual and Extended Summer	\$60.02	\$29.87	
RTO	Coupled	Annual and Limited			
RTO	Coupled	Extended Summer and Limited		\$47.97	\$29.82
RTO	Coupled	Annual, Extended Summer, and Limited	\$53.15	\$35.97	\$52.30
PSEG	Non-coupled	Annual	\$70.98		
PSEG	Non-coupled	Extended Summer		\$49.97	
PSEG	Non-coupled	Limited			\$9.34
PSEG	Coupled	Annual and Extended Summer	\$82.73	\$58.88	
PSEG	Coupled	Annual and Limited			
PSEG	Coupled	Extended Summer and Limited		\$58.75	\$31.42
PSEG	Coupled	Annual, Extended Summer, and Limited	\$109.65	\$77.70	\$87.95
PPL	Non-coupled	Annual	\$40.33		
PPL	Non-coupled	Extended Summer		\$35.16	
PPL	Non-coupled	Limited			\$95.12
PPL	Coupled	Annual and Extended Summer	\$83.02	\$59.36	
PPL	Coupled	Annual and Limited			
PPL	Coupled	Extended Summer and Limited		\$61.28	\$42.44
PPL	Coupled	Annual, Extended Summer, and Limited	\$78.83	\$40.04	\$45.61

Table 19 Impact of DR product types: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		Annual Resources Only	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1		
	Extended Summer	\$120.00	7,163.3		
	Annual	\$120.00	157,518.3	\$157.80	166,237.1
RTO Total			167,003.7		166,237.1
PSEG	Limited	\$201.02	177.5		
	Extended Summer	\$215.00	154.8		
	Annual	\$215.00	5,778.4	\$220.00	6,103.4
PSEG Total			6,110.7		6,103.4
PPL	Limited	\$40.00	41.7		
	Extended Summer	\$53.98	183.3		
	Annual	\$120.00	9,123.5	\$157.80	10,543.8
PPL Total			9,348.5		10,543.8

Table 20 Impact of Short Term Resource Procurement Target and DR product types: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		No Short-Term Resource Procurement Target Reduction and Annual Resources Only	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1		
	Extended Summer	\$120.00	7,163.3		
	Annual	\$120.00	157,518.3	\$173.76	170,037.8
RTO Total			167,003.7		170,037.8
PSEG	Limited	\$201.02	177.5		
	Extended Summer	\$215.00	154.8		
	Annual	\$215.00	5,778.4	\$225.00	6,381.6
PSEG Total			6,110.7		6,381.6
PPL	Limited	\$40.00	41.7		
	Extended Summer	\$53.98	183.3		
	Annual	\$120.00	9,123.5	\$173.76	10,546.7
PPL Total			9,348.5		10,546.7

Table 21 Impact of demand side products: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		No Offers for DR or EE	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1		
	Extended Summer	\$120.00	7,163.3		
	Annual	\$120.00	157,518.3	\$282.16	163,713.2
RTO Total			167,003.7		163,713.2
PSEG	Limited	\$201.02	177.5		
	Extended Summer	\$215.00	154.8		
	Annual	\$215.00	5,778.4	\$282.16	6,177.1
PSEG Total			6,110.7		6,177.1
PPL	Limited	\$40.00	41.7		
	Extended Summer	\$53.98	183.3		
	Annual	\$120.00	9,123.5	\$282.16	9,879.3
PPL Total			9,348.5		9,879.3

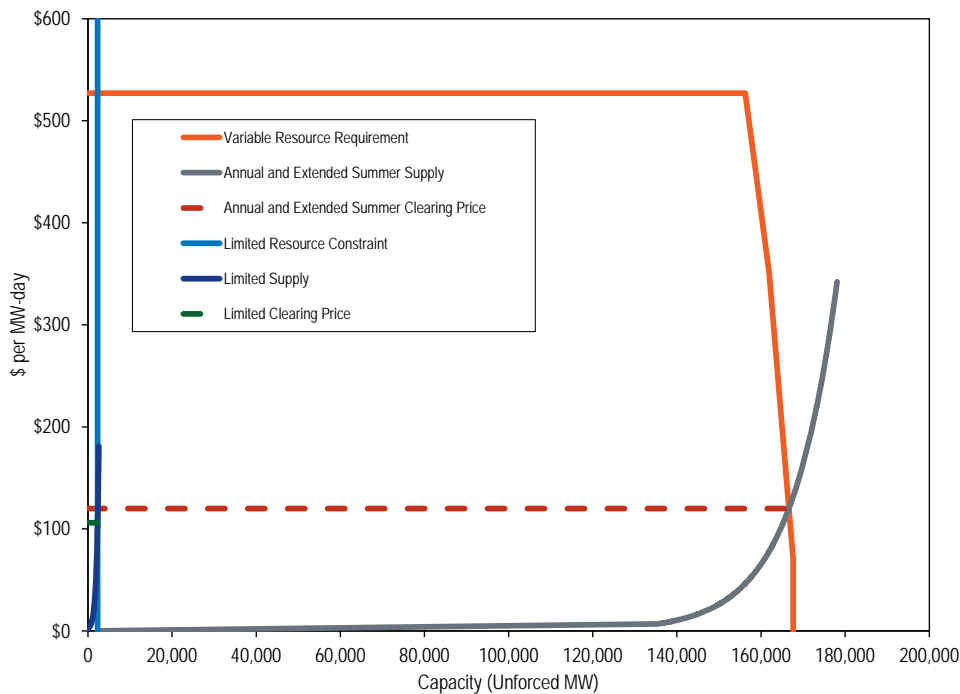
Table 22 Impact of environmental regulations: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		Remove APIR Associated with Environmental Regulations	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1	\$118.06	2,322.1
	Extended Summer	\$120.00	7,163.3	\$120.00	7,164.2
	Annual	\$120.00	157,518.3	\$120.00	157,489.6
RTO Total			167,003.7		166,975.9
PSEG	Limited	\$201.02	177.5	\$213.06	177.7
	Extended Summer	\$215.00	154.8	\$215.00	154.6
	Annual	\$215.00	5,778.4	\$215.00	5,778.6
PSEG Total			6,110.7		6,110.9
PPL	Limited	\$40.00	41.7	\$40.00	41.7
	Extended Summer	\$53.98	183.3	\$41.94	183.3
	Annual	\$120.00	9,123.5	\$120.00	9,123.5
PPL Total			9,348.5		9,348.5

Table 23 Impact of capacity imports: 2017/2018 RPM Base Residual Auction

LDA	Product Type	Actual Auction Results		Reduce Imports by 25 Percent		Reduce Imports by 50 Percent		Reduce Imports by 75 Percent		Exclude Imports without Pseudo Ties	
		Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)	Clearing Prices (\$ per MW-day)	Cleared UCAP (MW)
RTO	Limited	\$106.02	2,322.1	\$125.42	2,322.1	\$150.56	2,322.1	\$162.16	2,322.1	\$109.56	2,322.1
	Extended Summer	\$120.00	7,163.3	\$132.07	7,210.7	\$150.56	7,285.4	\$167.17	7,288.7	\$124.56	7,164.2
	Annual	\$120.00	157,518.3	\$132.07	157,205.8	\$150.56	156,762.0	\$167.17	156,035.6	\$124.56	157,425.0
RTO Total			167,003.7	166,738.6		166,369.5		165,646.4		166,911.3	
PSEG	Limited	\$201.02	177.5	\$208.35	177.5	\$215.00	173.5	\$209.99	173.5	\$200.00	177.7
	Extended Summer	\$215.00	154.8	\$215.00	154.8	\$215.00	158.9	\$215.00	158.9	\$215.00	154.6
	Annual	\$215.00	5,778.4	\$215.00	5,778.7	\$215.00	5,778.5	\$215.00	5,778.5	\$215.00	5,778.6
PSEG Total			6,110.7	6,111.0		6,110.9		6,110.9		6,110.9	
PPL	Limited	\$40.00	41.7	\$40.00	41.7	\$43.84	46.9	\$75.00	63.7	\$40.00	41.7
	Extended Summer	\$53.98	183.3	\$46.65	183.3	\$43.84	178.1	\$80.01	161.3	\$55.00	183.3
	Annual	\$120.00	9,123.5	\$132.07	9,731.0	\$150.56	10,048.8	\$167.17	10,424.5	\$124.56	9,430.4
PPL Total			9,348.5	9,956.0		10,273.8		10,649.5		9,655.4	

Figure 1 RTO market supply/demand curves: 2017/2018 RPM Base Residual Auction^{109 110 111}



¹⁰⁹ 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.

¹¹⁰ For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve and Limited Resource Constraint exclude incremental demand which cleared in PSEG.

¹¹¹ The Sub-Annual Resource Constraint was not a binding constraint in RTO in the 2017/2018 RPM Base Residual Auction.

PSEG LDA Market Results

Table 24 shows total PSEG LDA offer data for the 2017/2018 RPM Base Residual Auction. Total internal PSEG LDA unforced capacity of 6,924.7 MW includes all Generation Capacity Resources, Demand Resources, and Energy Efficiency Resources that qualified as PJM Capacity Resources, excludes external units, and also includes owners' modifications to ICAP ratings. As shown in Table 8, PSEG LDA unforced internal capacity decreased 1,418.4 MW from 8,343.1 MW in the 2016/2017 BRA as a result of net generation capacity modifications (-1,132.4 MW), net DR modifications (-167.9 MW), and net EE modifications (4.4 MW), the EFORD effect due to higher sell offer EFORDs (-122.1 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-0.4 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the RTO, so total PSEG LDA RPM capacity was the same as the internal capacity of 6,924.7 MW.¹¹² There were no exports from PSEG LDA. Subtracting 91.6 MW of DR and EE not offered resulted in available unforced capacity in PSEG LDA of 6,833.1 MW.¹¹³ After accounting for these exceptions, all capacity resources in PSEG were offered in the RPM Auction.

The PSEG LDA import limit was a binding constraint in the 2017/2018 BRA. Of the 6,110.7 MW cleared in PSEG LDA, 5,735.1 MW were cleared in the RTO before PSEG LDA became constrained. Once the constraint was binding, based on the 6,700.0 MW CETL value, only the incremental supply located in PSEG LDA was available to meet the incremental demand in the LDA. Of the incremental supply, 375.6 MW cleared, which resulted in a clearing price for Extended Summer and Annual Resources of \$215.00 per MW-day, as shown in Figure 2. The clearing price was determined by the intersection of the incremental supply and VRR curve.

The Limited Resource Constraint was a binding constraint for RTO in the 2017/2018 BRA, and as a result Limited Resources in PSEG LDA received a clearing price of \$201.02 per MW-day.

¹¹² PJM. "Manual 18: PJM Capacity Market," Revision 24 (July 31, 2014), p. 46.

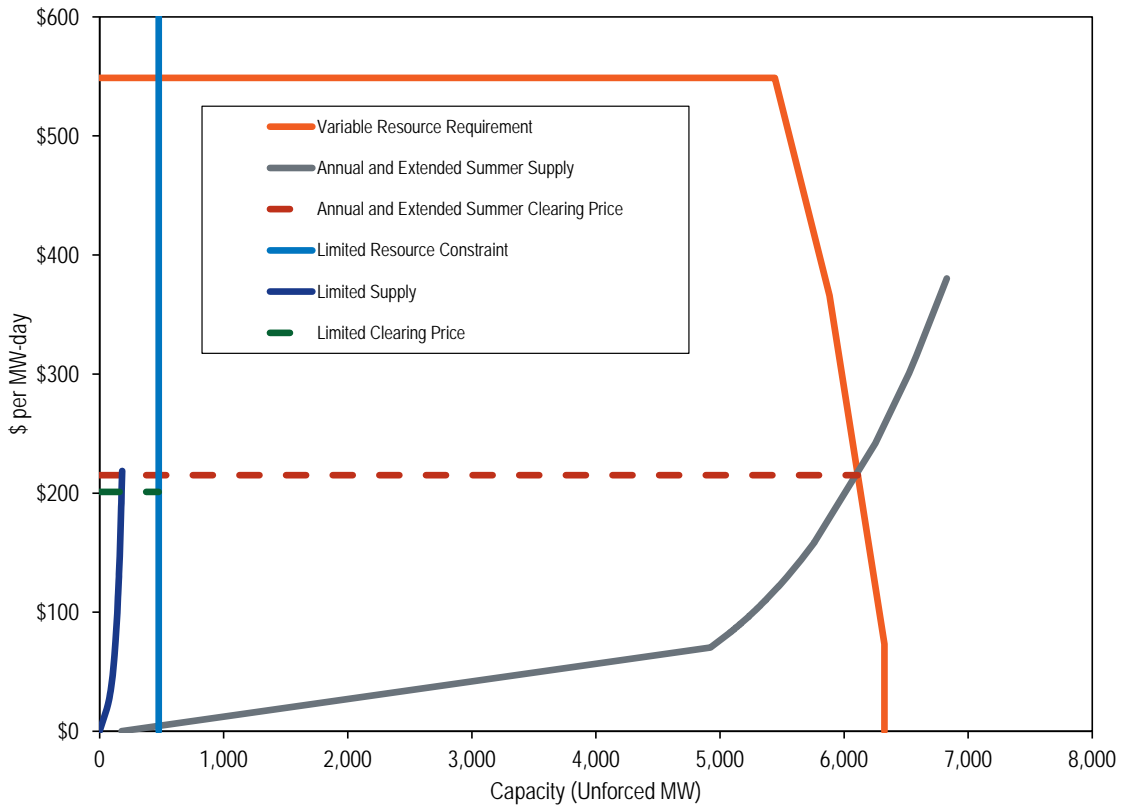
¹¹³ Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

Table and Figures for PSEG LDA

Table 24 PSEG LDA offer statistics: 2017/2018 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	6,851.6	6,421.7		
DR capacity	464.9	483.5		
EE capacity	19.0	19.5		
Total internal PSEG LDA capacity	7,335.5	6,924.7		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	7,335.5	6,924.7		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	0.0	0.0		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered DR and EE	(88.3)	(91.6)		
Available	7,247.2	6,833.1	100.0%	100.0%
Generation offered	6,851.6	6,421.7	94.5%	94.0%
DR offered	377.4	392.7	5.2%	5.7%
EE offered	18.2	18.7	0.3%	0.3%
Total offered	7,247.2	6,833.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		5,735.1		83.9%
Cleared in PSEG		375.6		5.5%
Total cleared		6,110.7		89.4%
Make-whole		0.0		0.0%
Reliability requirement		12,759.0		
Total cleared plus make-whole		6,110.7		
CETL		6,700.0		
Total Resources		12,810.7		
Short-Term Resource Procurement Target		285.7		
Net excess/(deficit)		337.4		
Resource clearing price for Limited Resources (\$ per MW-day)		\$201.02		
Resource clearing price for Extended Summer Resources (\$ per MW-day)		\$215.00		
Resource clearing price for Annual Resources (\$ per MW-day)		\$215.00		
Preliminary zonal capacity price (\$ per MW-day)		\$214.92	A	
Base zonal CTR credit rate (\$ per MW-day)		\$39.72	B	
Preliminary net load price (\$ per MW-day)		\$175.21	A-B	

Figure 2 PSEG LDA market supply/demand curves: 2017/2018 RPM Base Residual Auction^{114 115}



PPL LDA Market Results

Table 25 shows total PPL LDA offer data for the 2017/2018 RPM Base Residual Auction. Total internal PPL LDA unforced capacity of 11,072.1 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 8, PPL LDA unforced internal capacity increased 501.4 MW from 10,570.7 MW in the 2016/2017 BRA as a result of net generation capacity modifications (910.0 MW), net DR modifications (-171.2 MW), and

¹¹⁴ For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve is reduced by the CETL.

¹¹⁵ The Limited Resource Constraint was not a binding constraint in PSEG LDA in the 2017/2018 RPM Base Residual Auction.

net EE modifications (-1.0 MW), the EFORd effect due to higher sell offer EFORds (-236.1 MW), and the DR and EE effect due to a lower Load Management UCAP conversion factor (-0.3 MW).

All imports offered in the auction from areas external to PJM are modeled as supply in the RTO, so total PPL LDA RPM capacity was the same as the internal capacity of 11,072.1 MW.¹¹⁶ There were no exports from PPL LDA. RPM capacity was reduced by 265.6 MW excused from the RPM must offer requirement. The excused Existing Generation Capacity Resources were the result of plans for retirement (265.6 MW). Subtracting 78.9 MW of DR and EE not offered, resulted in available unforced capacity in PPL LDA of 10,727.6 MW.¹¹⁷ After accounting for these exceptions, all capacity resources in PPL LDA were offered in the RPM Auction.

The PPL LDA import limit was not a binding constraint in the 2017/2018 BRA. The PPL LDA Sub-Annual Resource Constraint was binding in the 2017/2018 BRA. The Limited Resource Constraint was a binding constraint for RTO in the 2017/2018 BRA. As a result, the PPL LDA clearing price for Annual Resources was based on the RTO clearing price, the PPL LDA clearing price for Extended Summer Resources was based on the PPL Sub-Annual Resource Price Decrement, and the PPL LDA clearing price for Limited Resources was based on both the PPL Sub-Annual Resource Price Decrement and the RTO Limited Resource Price Decrement. See Figure 3.

¹¹⁶ PJM. "Manual 18: PJM Capacity Market," Revision 24 (July 31, 2014), p. 46.

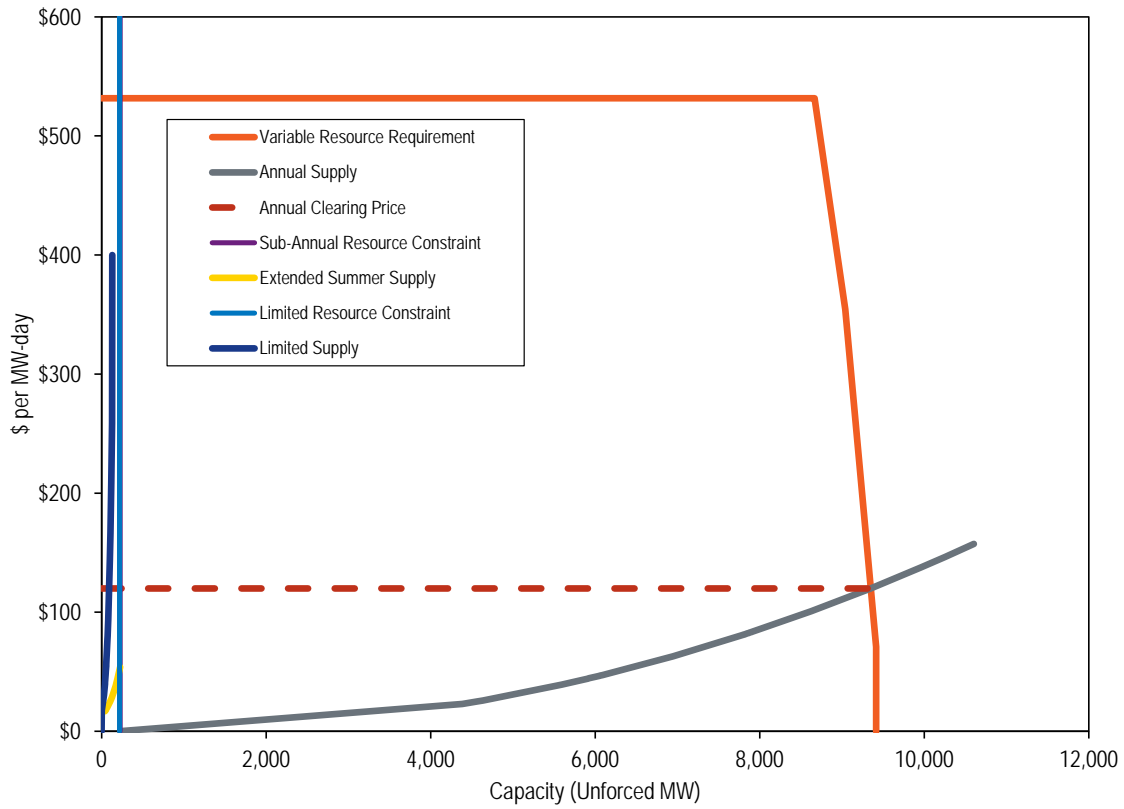
¹¹⁷ Unoffered DR and EE MW include PJM approved DR and EE modifications that were not offered in the auction.

Table and Figure for PPL LDA

Table 25 PPL LDA offer statistics: 2017/2018 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Generation capacity	10,716.5	10,144.9		
DR capacity	857.2	891.6		
EE capacity	34.0	35.6		
Total internal PPL LDA capacity	11,607.7	11,072.1		
FRR	0.0	0.0		
Imports	0.0	0.0		
RPM capacity	11,607.7	11,072.1		
Exports	0.0	0.0		
FRR optional	0.0	0.0		
Excused Existing Generation Capacity Resources	(347.0)	(265.6)		
Unoffered Planned Generation Capacity Resources	0.0	0.0		
Unoffered DR and EE	(76.0)	(78.9)		
Available	11,184.7	10,727.6	100.0%	100.0%
Generation offered	10,369.5	9,879.3	92.7%	92.1%
DR offered	781.2	812.7	7.0%	7.6%
EE offered	34.0	35.6	0.3%	0.3%
Total offered	11,184.7	10,727.6	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO		9,348.5		87.1%
Cleared in PPL		0.0		0.0%
Total cleared		9,348.5		87.1%
Make-whole		0.2		0.0%
Reliability requirement		10,813.0		
Total cleared plus make-whole		9,348.7		
CETL		4,336.0		
Total Resources		13,684.7		
Short-Term Resource Procurement Target		205.1		
Net excess/(deficit)		3,076.8		
Resource clearing price for Limited Resources (\$ per MW-day)		\$40.00		
Resource clearing price for Extended Summer Resources (\$ per MW-day)		\$53.98		
Resource clearing price for Annual Resources (\$ per MW-day)		\$120.00		
Preliminary zonal capacity price (\$ per MW-day)		\$118.18	A	
Base zonal CTR credit rate (\$ per MW-day)		\$0.00	B	
Preliminary net load price (\$ per MW-day)		\$118.18	A-B	

Figure 3 PPL LDA market supply/demand curves: 2017/2018 RPM Base Residual Auction^{118 119}



¹¹⁸ For uncleared coupled DR offers, the offer with the lowest sell offer price within a coupled Demand Resource group was assumed in graphing the supply curve. The VRR curve is reduced by the CETL.

¹¹⁹ The import limited and the Limited Resource Constraint were not binding constraints in PPL LDA in the 2017/2018 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.¹²⁰ 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

¹²⁰ 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 adders for Limited and Extended Summer DR products 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 2017/2018 RPM Base Residual Auction conducted by PJM were replicated using the MMU's approach. The total MW cleared for every nested LDA using the MMU's algorithm is within 0.000018 percent of the corresponding total MW cleared under PJM's method. The clearing prices using the MMU's approach were identical to 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 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 above condition may no longer hold. Therefore, this enhancement necessitates a re-evaluation of how MCPs are determined.

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 4 and Figure 5 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.¹²¹

¹²¹ For simplicity, the minimum annual resource requirement and minimum summer extended resource requirement constraints are not included.

Figure 4 Variable Resource Requirement Curve: Child LDA

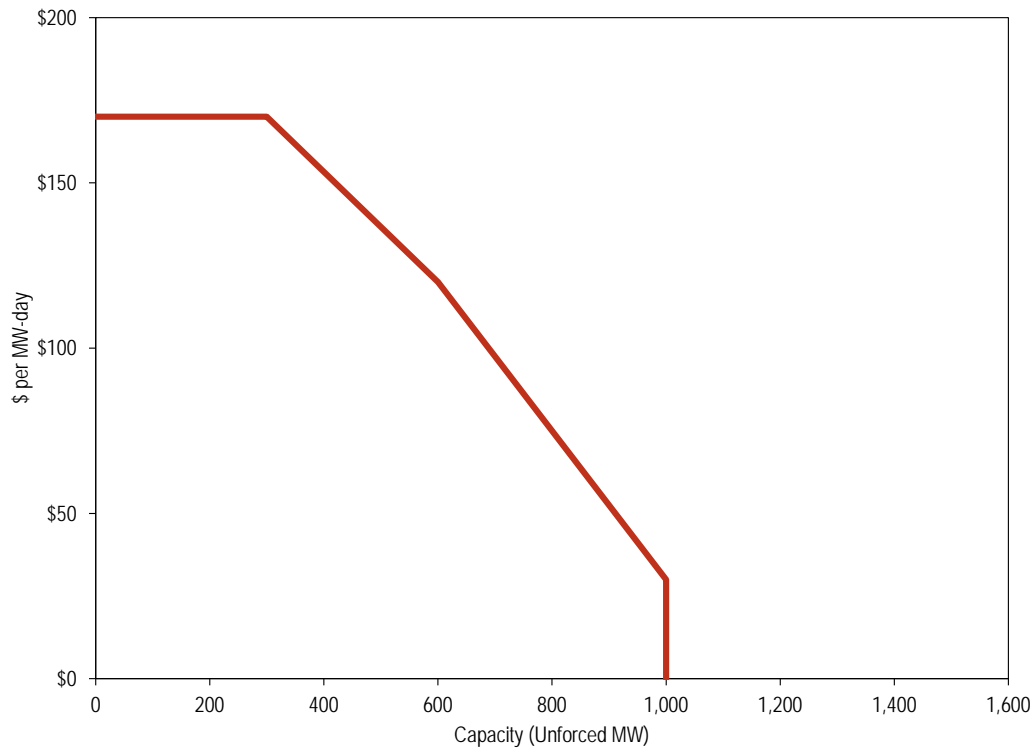


Figure 5 Nested Variable Resource Requirement Curve: Parent LDA

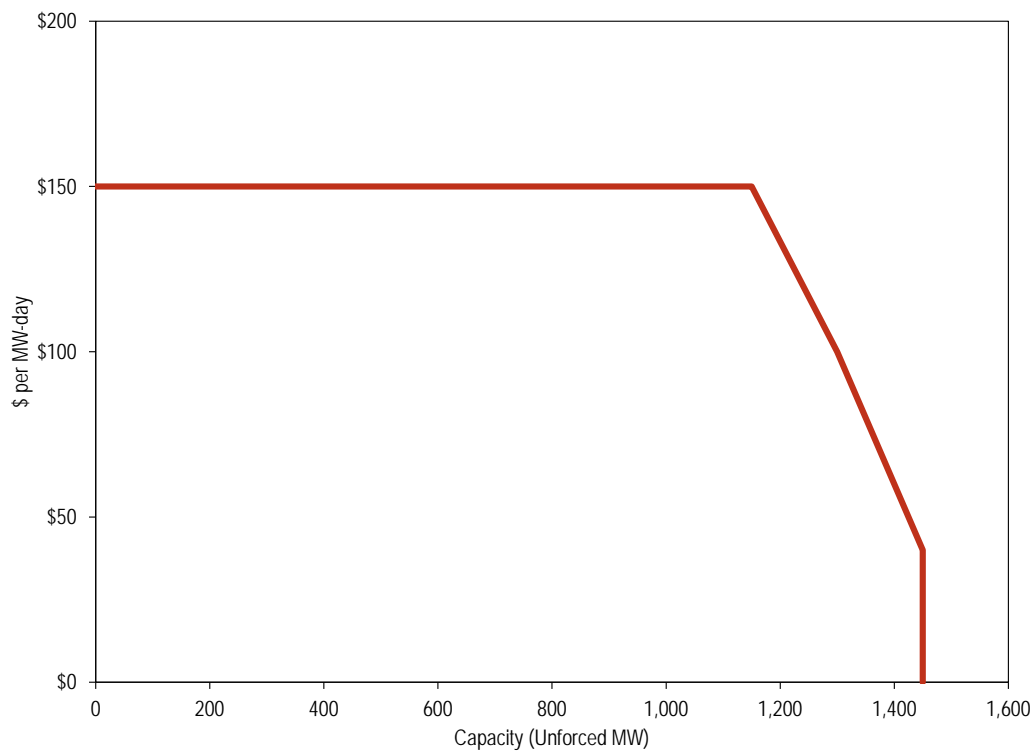


Figure 6 and Figure 7 illustrate the solution for the first scenario. Only 189.1 MW of the available 300 MW CETL is utilized. Therefore the CETL constraint is non-binding and out of merit offers are not needed to meet the child LDA's Variable Resource Requirement. The marginal clearing price for both the parent and child LDA is \$120.00.

Figure 6 Optimal solution for scenario 1: Child LDA

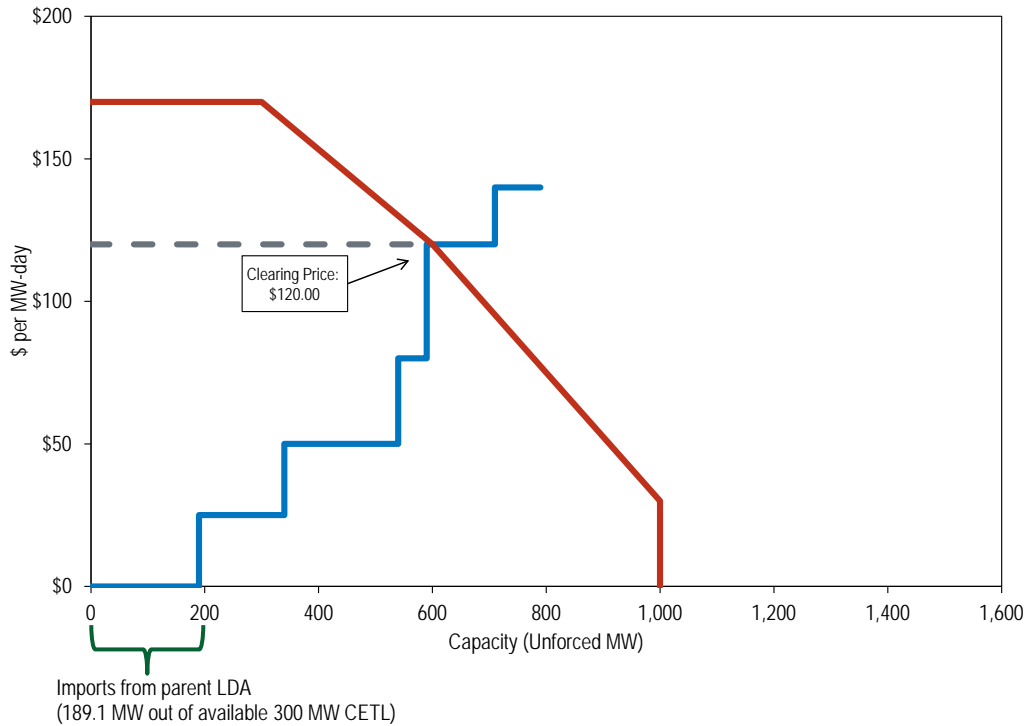


Figure 7 Optimal solution for scenario 1: Parent LDA

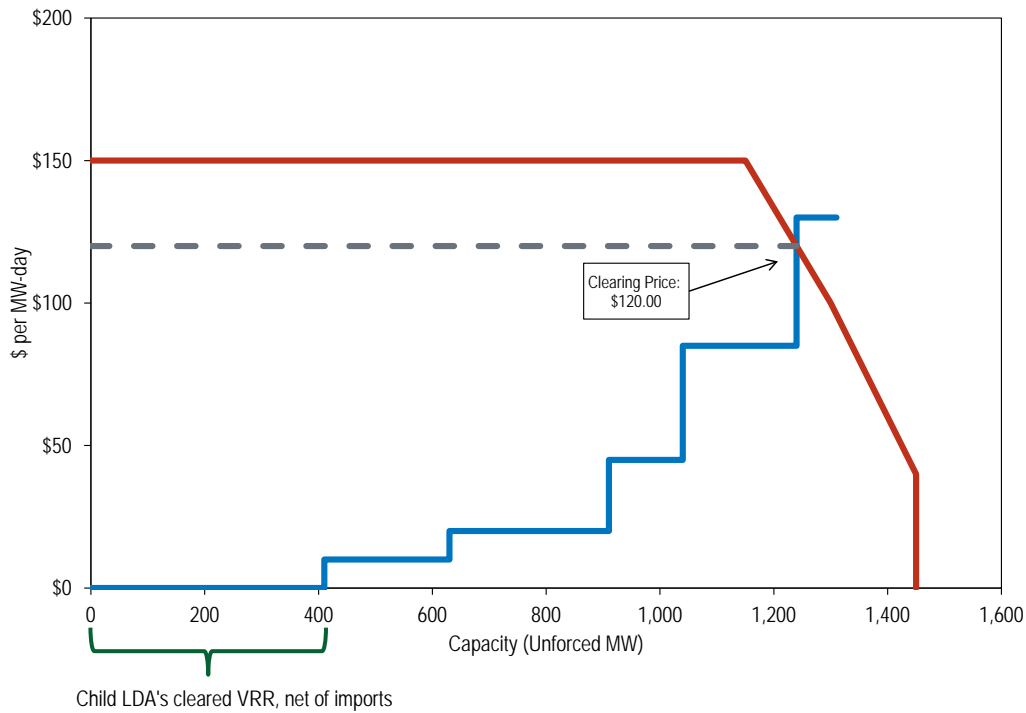


Figure 8 and Figure 9 illustrate the solution for the second scenario. The only difference between first and second scenarios is that the CETL is 150 MW in the second scenario compared to 300 MW in the first scenario. The solution shows that the entire 150 MW available is utilized by the child LDA to 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 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 8 Optimal solution for scenario 2: Child LDA

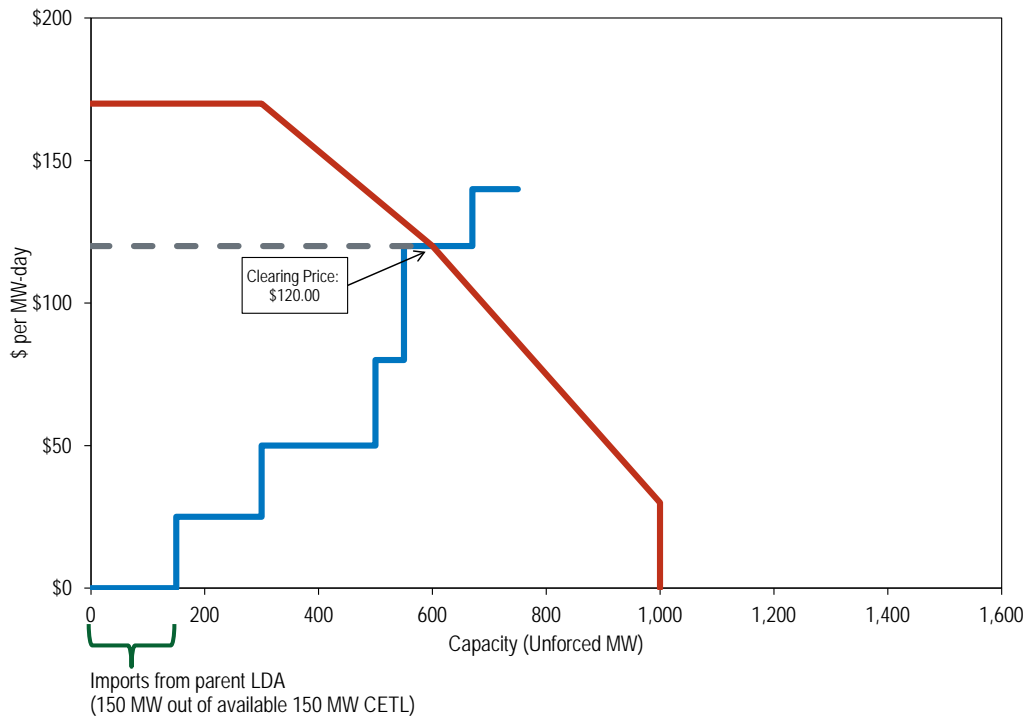


Figure 9 Optimal solution for scenario 2: Parent LDA

