Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2017, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The capacity market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

5 See 126 FERC ¶ 61,275 (2009) at P 86.

increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

The 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 2017.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[9] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[10] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2017, PJM installed capacity increased 1,470.9 MW or 0.8 percent, from 182,410.7 MW on January 1 to 183,881.6 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2017, 35.4 percent was coal; 36.8 percent was gas; 18.0 percent was nuclear; 3.6 percent was oil; 4.8 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.2 percent was solar.

6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 See 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 9.
10 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant delivery year decreased 7,225.8 MW from 200,848.1 MW on June 1, 2016, to 193,622.3 MW on June 1, 2017. This decrease was the result of new generation (5,179.3 MW), reactivated generation (1,025.7 MW), net generation capacity modifications (cap mods) (-7,943.1 MW), demand resource (DR) modifications (-3,472.4 MW), energy efficiency (EE) modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and lower load management UCAP conversion factor (-7.1 MW).
- **Demand.** There was a 787.1 MW decrease in the RPM reliability requirement from 180,332.2 MW on June 1, 2016, to 179,545.1 MW on June 1, 2017. 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 Forecast Pool Requirement (FPR) constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in FPR. On June 1, 2017, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 63.6 percent, down from 64.1 percent on June 1, 2016.
- **Market Concentration.** In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO passed the three pivotal supplier (TPS) test. In the 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2017/2018 RPM Third Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, 2019/2020 RPM Base Residual Auction, 2019/2020 RPM First Incremental Auction, and the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation 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, increased the market clearing price.[12] [13] [14]
- **Imports and Exports.** Of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for demand resources and energy efficiency resources in RPM Auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity from sources other than demand resources and energy efficiency (3,675.2 MW).

Market Conduct

- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources that submitted offers, the MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 (33.3 percent) were based on the technology specific default (proxy) ACR values and 131 (10.9 percent) were unit-specific offer caps.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 (30.5 percent) were based on the technology specific default

11 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

12 See OATT Attachment DD § 6.5.

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

14 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).

(proxy) ACR values and 17 (14.4 percent) were unit-specific offer caps.

- **2017/2018 RPM Second Incremental Auction.** Of the 95 generation resources that submitted offers, the MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 (15.8 percent) were based on the technology specific default (proxy) ACR values and 20 (21.1 percent) were unit-specific offer caps.
- **2017/2018 RPM Third Incremental Auction.** Of the 310 generation resources that submitted offers, the MMU calculated offer caps for nine generation resources (2.9 percent), of which five (1.6 percent) were based on the technology specific default (proxy) ACR values and four (1.3 percent) were unit-specific offer caps.
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).

Market Performance

- The 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted in 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.19 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $175.58, including all RPM auctions for the 2018/2019 Delivery Year held through 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $113.41, including all RPM Auctions for the 2019/2020 Delivery Year held through 2017.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $121.84 per MW-day in 2016/2017 and $141.19 per MW-day in 2017/2018.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2017 was 6.8 percent, an increase from 6.5 percent for 2016.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2017 was 84.1 percent, an increase from 83.4 percent for 2016.
- **Outages Deemed Outside Management Control (OMC).** In 2017, 2.9 percent of forced outages were classified as OMC outages.

Recommendations[16]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

Definition of Capacity

- 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.[18] [19] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the definition of demand side resources be modified to ensure that such resources be fully substitutable for other generation capacity 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. (Priority: High. First reported 2012. Status: Adopted 2015.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[20] [21] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method.

15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on January 24, 2018. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

16 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

17 151 FERC ¶ 61,208 (June 9, 2015).

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

19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

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

21 See the *2012 State of the Market Report for PJM*, Volume 2, Section 6: Net Revenue.

If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)

Offer Caps and Offer Floors

- The MMU recommends the extension of the minimum offer price rule (MOPR) to all existing and proposed units (MOPR-Ex) in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. Status: Not adopted.)
- 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.[22] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported Q3, 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Hours (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Hours to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction. (Priority: High. First reported Q3, 2017. Status: Not adopted.)

22 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).

- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE*B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. New Recommendation. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The Market Monitor recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
  - 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. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Status: Adopted 2015.)
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[23] (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are full substitutes for internal, physical capacity resources. (Priority: High. First reported 2014. Status: Adopted 2015.)
- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

23 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, joint report, "*Capacity in the PJM Market*," (August 20, 2012).<http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf>

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in 2017. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The exception was that some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping. The PJM capacity market results were competitive in 2017.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24 25 26 27 28 29] In 2016 and 2017, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the CP Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2017. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding and the request in Pennsylvania to subsidize the TMI nuclear power plant and the DOE NOPR, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested

24 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

25 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

26 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

27 See "Analysis of the 2020/2021 RPM Base Residual Auction," <<http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf>> (November 11, 2017).

28 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be extended (MOPR-Ex) to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Table 5-2 RPM related MMU reports: 2016 through 2017

Date	Name
January 13, 2016	IMM Response re Capacity Performance Docket No. ER15-623-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Response_ER15-623-000_20160113.pdf
February 1, 2016	IMM Post-Hearing Brief re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1693_and_14-1694_20160201.pdf
February 8, 2016	IMM Post-Hearing Reply Brief re AEP Ohio Case Nos. 14-1693-EL-RDR and 14-1694-EL-AAM http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1693-14-1694_20160208.pdf
February 11, 2016	PJM IMM Joint Statement re Capacity Performance Docket Nos. ER15-623-000, -004 and EL15-29-000, and -003 http://www.monitoringanalytics.com/reports/Reports/2016/PJM_IMM_Joint_Statement_Docket_Nos_ER15-623-000_004_EL15-29-000_003_20160211.pdf
February 16, 2016	IMM Post-Hearing Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Brief_Case_No_14-1297_20160216.pdf
February 24, 2016	IMM Comments re DR CBL Testing http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_Nos_ER16-873_20160223.pdf
February 25, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20160225.pdf
February 26, 2016	IMM Post-Hearing Reply Brief re FE Ohio Case No. 14-1297-EL-SSO http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Post_Hearing_Reply_Brief_Case_No_14-1297-EL-SSO_20160226.pdf
March 22, 2016	IMM Answer re DR CBL Docket No. ER16-873-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-873-000_20160322.pdf
March 28, 2016	IMM Motion for Clarification or Rehearing re Net Revenue Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Request_for_Rehearing_EL14-94-000_20160328.pdf
April 11, 2016	IMM Comments re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_EL16-49-000_20160411.pdf
April 22, 2016	IMM Comments re Ramp Rate Capacity Performance Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER16-1336_20160422.pdf
April 28, 2016	IMM Answer re Calpine Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160428.pdf
May 4, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf
May 9, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20160509.pdf
May 11, 2016	IMM Answer re Capacity Performance PAH Ramp Rate Docket No. ER16-1336-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_ER16-1336-000_20160511.pdf
June 13, 2016	IMM Answer and Motion for Leave to Answer re Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_No_EL16-49-000_20160613.pdf
June 24, 2016	IMM Answer to IMEA RFR Docket No. ER15-623-010, EL15-29-006 and EL15-41-002 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Answer_Docket_Nos_ER15-623-010_EL15-29-006_EL15-41-002_20160624.pdf
July 6, 2016	Analysis of the 2018/2019 RPM Base Residual Auction Revised http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf
July 7, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20160707.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 ppt http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_PPT_20160706.pdf
July 13, 2016	New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019 http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_New_Generation_in_the_PJM_Capacity_Market_for_Delivery_Years_20072008_through_20182019_20160706.pdf
August 26, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20160826.pdf
August 31, 2016	Analysis of the 2019/2020 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf
September 14, 2016	Capacity Release Proposal http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MIC_Capacity_Release_Proposal_20160914.pdf
November 22, 2016	IMM Complaint re Manual 18 Revisions Docket No. EL17-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Complaint_Docket_No_EL17-_20161122.pdf
December 8, 2016	IMM Comments re CP Aggregate Rules Docket No. ER17-367-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_ER17-367-000_20161208.pdf
December 22, 2016	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20161222.pdf
December 22, 2016	IMM Notice of Withdrawal re PJM Manual 18 Complaint Docket No. EL17-23-000 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Notice_of_Withdrawal_Docket_No_EL17-23_20161222.pdf
December 27, 2016	IMM Analysis of Replacement Capacity for RPM Commitments: June 01, 2007 to June 01, 2016 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf
December 30, 2016	IMM Motion to Lodge and for Commencement of Compliance Process re RPM Revisions Docket No. ER14-1461-000, -001 http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Motion_to_Lodge_Docket_No_ER14-1461_20161230.pdf

Table 5-2 RPM related MMU reports: 2016 through 2017

Date	Name
January 11, 2017	Replacement Capacity http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MIC_Replacement_Capacity_Report_20170111.pdf
January 24, 2017	Summary of BRA Analysis Results: 2013/2014 - 2019/2020 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_BRA_Scenario_Results_Summary_20170124.pdf
January 30, 2017	IMM Answer re Amended Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL16-49_20170130.pdf
February 13, 2017	IMM Answer re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_Nos_EL17-32_EL17-36_20170213.pdf
February 24, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20170224.pdf
March 1, 2017	Incremental Auction Review http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Incremental_Auction_Review_20170301.pdf
May 11, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
June 27, 2017	MMU Incremental Auction Recommendation - Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_MMU_Package_B_Summary_20170627.pdf
June 27, 2017	Replacement Capacity Issues http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Replacement_Capacity_Issues_20170627.pdf
August 30, 2017	IMM Answer re IMM MOPR Exemption Complaint Docket No. EL17-82 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL17-82_20170830.pdf
August 30, 2017	Incremental Auction Design Changes, Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Package_B_Executive_Summary_20170830.pdf
September 5, 2017	IMM Comments re PJM Deficiency Letter Compliance Docket No. ER17-775-002 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775-002_20170905.pdf
September 8, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
September 11, 2017	IMM CCPPSTF Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_20170911.pdf
September 12, 2017	IMM Answer re Pleasants Transfer Docket No. EC17-88 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EC17-88_20170912.pdf
October 17, 2017	Revised IMM MOPR-Ex Proposal for CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_Letter_CCPPSTF_IM_%20Proposal_Summary_Revised_20171017.pdf
November 2, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_20171103.pdf
November 12, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_3_Redline_20171112.pdf
November 14, 2017	IMM Answer re MOPR Reforms Docket No. ER13-535 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_ER13-535_20171114.pdf
November 17, 2017	Analysis of 2020/2021 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf
December 12, 2017	IMM MOPR-Ex RPS Status http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR-Ex_RPS_Status_20171212.pdf
December 12, 2017	IMM MOPR-Ex Proposal Language - Revised http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR_Ex_Proposal_Language_Revised_20171212.pdf
December 14, 2017	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf
December 21, 2017	MOPR-Ex Proposal Language Revised - 2 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_2_2017121.pdf
December 21, 2017	MOPR-Ex Proposal Language - Revised 3 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_3_20171213.pdf
December 21, 2017	IMM MOPR-Ex RPS Status Revisions http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_RPS_Status_Revisions_20171214.pdf
December 21, 2017	MOPR-Ex Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_Proposal_20171221.pdf
December 22, 2017	IMM Parameter Limited Schedule Matrix (Annual) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Parameter_Limited_Schedule_Market_Notice_20171222.pdf
December 27, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20171227.pdf

Installed Capacity

On January 1, 2017, PJM installed capacity was 182,410.7 MW (Table 5-3).[30] Over the next 12 months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 183,881.6 MW on December 31, 2017, an increase of 1,470.9 MW or 0.8 percent from the January 1 level.[31] [32] The 1,470.9 MW increase was the result of capacity modifications (599.6 MW), new or reactivated generation (3,828.9 MW), and a decrease in exports (267.1 MW), offset by deactivations (2,031.7 MW), derates (757.9 MW), and a decrease in imports (435.1 MW).

At the beginning of the new delivery year on June 1, 2017, PJM installed capacity was 183,099.2 MW, a decrease of 386.8 MW or 0.2 percent from the May 31 level.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2017, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2017.[33] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 35.9 percent on June 1, 2017 and is projected to decrease to 26.7 percent by June 1, 2020. The share of gas increased from 29.1 percent in 2007 to 36.3 percent in 2017 and is projected to increase to 47.9 percent in 2020.

Table 5-4 shows the PJM installed capacity on June 1, 2017, for the top five generation capacity resource owners.

30 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

31 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

32 Wind resources accounted for 1,136.7 MW, and solar resources accounted for 373.2 MW of installed capacity in PJM on December 31, 2017. PJM administratively reduces the capabilities of all wind generators to 13 percent and solar generators to 38 percent of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 12 (Jan. 1, 2017) at 19.

33 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2017

	1-Jan-17		31-May-17		1-Jun-17		31-Dec-17	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,622.2	36.5%	66,941.3	36.5%	65,688.0	35.9%	65,144.0	35.4%
Gas	65,110.3	35.7%	65,787.1	35.9%	66,397.6	36.3%	67,726.4	36.8%
Hydroelectric	8,850.4	4.9%	8,850.4	4.8%	8,870.2	4.8%	8,856.2	4.8%
Nuclear	33,043.4	18.1%	33,103.7	18.0%	33,163.5	18.1%	33,163.5	18.0%
Oil	6,733.6	3.7%	6,687.0	3.6%	6,684.4	3.7%	6,672.2	3.6%
Solar	262.3	0.1%	268.0	0.1%	366.8	0.2%	373.2	0.2%
Solid waste	769.4	0.4%	769.4	0.4%	814.4	0.4%	809.4	0.4%
Wind	1,019.1	0.6%	1,079.1	0.6%	1,114.3	0.6%	1,136.7	0.6%
Total	182,410.7	100.0%	183,486.0	100.0%	183,099.2	100.0%	183,881.6	100.0%

Figure 5-1 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2020

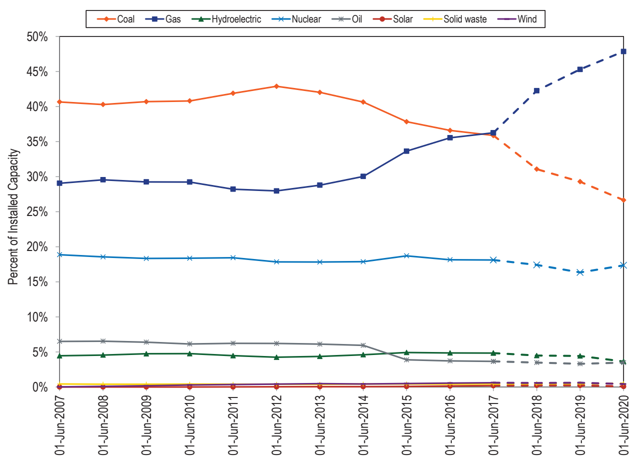


Table 5-4 PJM installed capacity by parent company: June 1, 2017

	01-Jun-17	
Parent Company	ICAP (MW)	Rank
Exelon Corporation	23,742.5	1
Dominion Resources, Inc.	21,298.0	2
American Electric Power Company, Inc.	17,132.1	3
FirstEnergy Corp.	16,680.2	4
NRG Energy, Inc.	16,288.2	5

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for PJM installed capacity.[34] The FDI_c is defined as $1 - \sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[35] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light control zones.[36] The FDI_c decreased on average 0.1 percent from 2016 to 2017. The average monthly capacity share of gas generators increased by 1.0 percentage point from 35.1 percent in 2016 to 36.1 percent in 2017. The average monthly capacity share of coal generators decreased by 0.8 percentage points from 36.9 percent in 2016 to 36.1 percent in 2017. Figure 5-2 also includes the expected FDI_c through June 2020 based on the clearing of RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement.[37] There were 118 units with installed capacity totaling 30.8 GW identified as the high estimate of being at risk. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from these 118 units that has cleared in a RPM auction is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.065 (9.4 percent) on average from the expected FDI_c for the period January 1, 2018, through June 1, 2020.

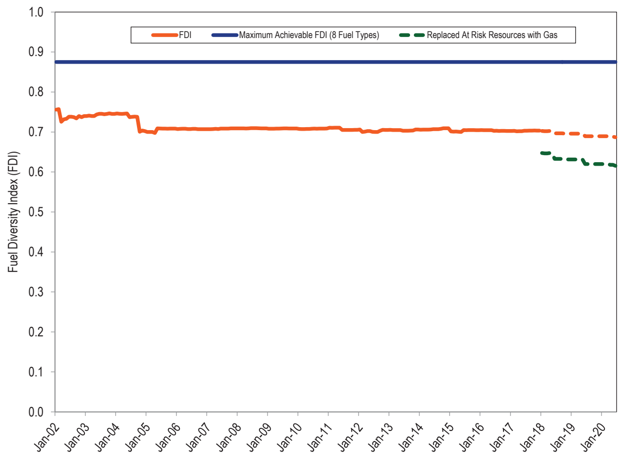
34 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

35 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

36 See the *2016 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

37 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 5-2 Fuel Diversity Index for PJM installed capacity: January 1, 2002 through June 1, 2020



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[38] In 2017, the 2017/2018 RPM Third Incremental Auction, the 2020/2021 RPM Base Residual Auction, the 2018/2019 RPM Second Incremental Auction, and the 2019/2020 RPM First Incremental Auction were conducted.

Market Structure

Supply

Table 5-5 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2016/2017 Delivery Year. The 19,439.8 MW increase was the result of new generation capacity resources (17,822.7 MW), reactivated generation capacity resources (967.0 MW), uprates (6,100.1 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (4,987.5 MW), a net decrease in capacity exports (2,298.3 MW), offset by deactivations (27,608.0 MW) and derates (3,236.8 MW).

As shown in Table 5-6, total internal capacity available to offer in the Base Residual Auction for the relevant delivery year decreased 7,225.8 MW from 200,848.1 MW on June 1, 2016, to 193,622.3 MW on June 1, 2017. This decrease was the result of new generation (5,179.3 MW), reactivated generation (1,025.7 MW), net generation capacity modifications (cap mods) (-7,943.1 MW), demand resource (DR) modifications (-3,472.4 MW), energy efficiency (EE) modifications (158.9 MW), the EFORd effect due to higher sell offer EFORds (-2,167.1 MW), and lower load management UCAP conversion factor (-7.1 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2018/2019, 2019/2020, and 2020/2021 auctions, new generation were 13,706.2 MW; reactivated generation were 5.3 MW; net generation cap mods were -6,554.7 and net generation winter cap mods were 409.2 MW. DR and energy efficiency (EE) modifications totaled -980.0 MW through June 1, 2020. An increase of 227.7 MW was due to lower EFORds, and an increase of 701.6 MW was due to a higher Load Management UCAP conversion factor. The net effect from June 1, 2017, through June 1, 2020, was an increase in total internal capacity available to offer in the Base Residual Auction for the relevant delivery year of 7,515.3 MW (3.9 percent) from 193,622.3 MW to 201,137.6 MW.

As shown in Table 5-6 and Table 5-15, in the 2017/2018 auction 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 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). 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

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

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 (168.3 MW), 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).

As shown in Table 5-6 and Table 5-16, in the 2018/2019 auction the 36 additional generation resources offered consisted of 28 new resources (3,447.4 MW), six additional resources imported (483.2 MW), and two resources that were previously entirely FRR committed (2.9 MW). The 28 new generation capacity resources consisted of 11 solar resources (82.8 MW), six wind resources (127.1 MW), four combined cycle resources (2,257.8 MW), four CT resources (912.3 MW), and three diesel resources (67.4 MW). The 49 fewer generation resources offered consisted of 22 fewer resources resulting from aggregation of RPM resources, 17 deactivated resources (1,083.2 MW), four planned generation capacity resources not offered (874.4 MW), three external resources not offered (446.1 MW), one resource excused from offering for reasons other than retirement (1.4 MW), one additional resource committed fully to FRR (173.0 MW), and one resource that is no longer a PJM capacity resource (2.3 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2017/2018 BRA: 16 steam resources (1,947.8 MW).

As shown in Table 5-6 and Table 5-17, in the 2019/2020 auction the 43 additional generation resources offered consisted of 39 new resources (6,685.5 MW), three additional resources imported (162.5 MW), and one resource that was unoffered in the 2018/2019 BRA (2.9 MW). The 39 new generation capacity resources consisted of 18 solar resources (152.3 MW), seven combined cycle resources (5,925.6 MW), five diesel resources (83.2 MW), five wind resources (73.0 MW), and four CT resources (451.4 MW). The 32 fewer generation resources offered consisted of 15 fewer resources resulting from aggregation of RPM resources, six deactivated resources (772.8 MW), five external resources not offered (956.6 MW), resources excused from offering for reasons other than retirement, and planned generation capacity resources not offered. In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2018/2019 BRA: two steam resources (148.9 MW) and one combustion turbine (0.8 MW).

As shown in Table 5-6 and Table 5-18, in the 2020/2021 auction the 35 additional generation resources offered consisted of 16 new resources (2,496.2 MW), six additional resources imported (MW), five resources that were previously entirely FRR committed (271.4 MW), four resources that were unoffered in the 2019/2020 BRA (495.5 MW), two reactivated resources (5.3 MW), and two additional resources resulting from the disaggregation of RPM resources. The 16 new generation capacity resources consisted of eight solar resources (64.0 MW), three combined cycle resources (2,382.5 MW), three diesel resources (24.3 MW), and two wind resources (25.4 MW). The 121 fewer generation resources offered consisted of 82 intermittent resources not offered (863.9 MW), 17 deactivated resources (4,123.8 MW), 14 generation resources excused from offering for reasons other than retirement (218.7 MW), four external resources not offered (166.5 MW), additional resources committed fully to FRR, planned generation capacity resources not offered, and capacity storage resources not offered.[39]

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the final peak load forecast for the given delivery year.

Future Changes in Generation Capacity[40]

As shown in Table 5-5, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2016/2017 Delivery Year, internal installed capacity decreased by 5,955.0 MW after accounting for new capacity resources, reactivations, and uprates (24,889.8 MW) and capacity deactivations and derates (30,844.8 MW).

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

40 For more details on future changes in generation capacity, see "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <www.monitoringanalytics.com> (March 9, 2018).

For the current and future delivery years (2017/2018 through 2020/2021), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Looking ahead, based on expected completion rates of cleared new generation capacity (10,245.9 MW) and pending deactivations (6,903.1 MW), PJM capacity is expected to increase by an additional 3,342.8 MW for the 2017/2018 through 2020/2021 Delivery Years.

Sources of Funding[41]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 17,822.7 MW (71.6 percent of all additions), with 12,527.9 MW from market funding and 5,294.8 MW from non-market funding. Reactivated generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 967.0 MW (3.9 percent of all additions), with 892.0 MW from market funding and 75.0 MW from non-market funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2016/2017 DY totaled 6,100.1 MW (24.5 percent of all additions), with 4,720.6 MW from market funding and 1,379.5 MW from nonmarket funding.

Of the 14,627.1 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years, that are not yet in service, 12,085.1 MW have market funding and 2,542.0 MW have non-market funding. Applying the historical completion rates, 8,414.6 MW, or 69.6 percent, of the market funded projects are expected to go into service. Similarly, 1,831.4 MW, or 72.0 percent, of nonmarket funded projects are expected to go into service. Together, 10,245.9 MW, or 70.0 percent, of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2020/2021 Delivery Year.

Of the 3,403.8 MW of the additional generation capacity that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years and are already in service, 3,239.6 MW (95.2 percent) are based on market funding. In summary, 15,324.7 MW (85.0 percent) of the additional generation capacity (3,239.6 MW in service and 12,085.1 MW not yet in service) that cleared in RPM auctions for the 2017/2018 through 2020/2021 delivery years are based on market funding. Capacity additions based on nonmarket funding are 2,706.2 MW (15.0 percent) of proposed generation that cleared at least one RPM auction for the 2017/2018 through 2020/2021 delivery years.

Table 5-5 Generation capacity changes: 2007/2008 to 2017/2018

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	168.6	1,074.0
2017/2018	183,099.2									
Total		17,822.7	967.0	6,100.1	18,109.0	4,987.5	(2,298.3)	27,608.0	3,236.8	19,439.8

41 For more details on sources of funding for generation capacity, see "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <www.monitoringanalytics.com> (March 9, 2018).

Table 5-6 Internal capacity: June 1, 2016 to June 1, 2020[42 43]

	UCAP (MW)														
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
Total internal capacity @ 01-Jun-16	200,848.1	74,717.9	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7		
Correction in resource modeling	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Adjusted internal capacity @ 01-Jun-16	200,848.1	74,718.7	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1	26,091.2	3,717.0	10,570.7		
New generation	5,179.3	3,599.6	1,663.2	856.3	0.0	2.8	0.0	0.0	770.2	0.0	3.4	122.7	959.9		
Reactivated generation	1,025.7	1,025.7	84.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(7,943.1)	(2,286.3)	(2,190.5)	(57.9)	5.7	(1,135.3)	(509.9)	15.7	(751.7)	(818.0)	85.1	0.0	(49.9)		
DR mods	(3,472.4)	(941.6)	(407.6)	(198.9)	(33.0)	(167.9)	(50.2)	(54.4)	(889.9)	(208.7)	497.8	635.1	(171.2)		
EE mods	158.9	91.4	26.9	61.5	0.9	4.4	0.1	77.2	(58.4)	(14.6)	583.3	50.9			
EFORd effect	(2,167.1)	(987.4)	(267.1)	(329.7)	(19.8)	(122.1)	(62.0)	35.1	(529.7)	(77.2)	33.6	(361.9)	(236.1)		
DR and EE effect	(7.1)	(2.5)	(1.4)	(0.4)	(0.2)	(0.4)	(0.2)	(0.3)	(1.3)	(0.4)		(0.1)	(0.3)		
Total internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,069.4	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1		
Correction in resource modeling	0.0	0.0	0.0	0.0	0.0	0.0	(19.9)	0.0	0.0	0.0	0.0	0.0	0.0		
Adjusted internal capacity @ 01-Jun-17	193,622.3	75,217.6	35,928.5	12,878.7	1,719.9	6,924.7	4,049.5	6,310.7	12,864.4	2,916.2	27,293.4	4,163.7	11,072.1		
New generation	3,988.3	1,054.8	1,036.1	0.0	50.0	981.2	0.0	0.0	0.0	0.0	245.6	0.0	0.0		
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(1,852.4)	399.2	(101.3)	(34.9)	(31.2)	(18.3)	(12.8)	0.0	(633.7)	(296.7)	(216.3)	(35.1)	89.5		
DR mods	746.6	198.4	67.6	28.7	30.5	(53.7)	(13.4)	23.9	(119.1)	(18.4)	589.6	5.0	69.1		
EE mods	(9.3)	(4.9)	(8.2)	3.2	(1.6)	4.7	2.2	(56.6)	(109.4)	(35.5)	136.1	59.8	4.4		
EFORd effect	(1,858.8)	(417.7)	(623.1)	(20.4)	12.3	(357.7)	(170.6)	(153.1)	39.2	89.7	(708.1)	131.9	24.6		
DR and EE effect	626.1	239.9	85.4	79.7	5.1	19.5	7.9	36.1	44.8	14.3	117.8	43.6	41.4		
Total internal capacity @ 01-Jun-18	195,262.8	76,687.3	36,385.0	12,935.0	1,785.0	7,500.4	3,862.8	6,161.0	12,086.2	2,669.6	27,458.1	4,368.9	11,301.1		
Correction in resource modeling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Adjusted internal capacity @ 01-Jun-18	195,262.8	76,687.3	36,385.0	12,935.0	1,785.0	7,500.4	3,862.8	6,161.0	12,086.2	2,669.6	27,458.1	4,368.9	11,301.1		
New generation	6,185.7	2,341.6	35.6	912.2	7.0	12.0	0.0	912.2	766.5	0.0	43.5	0.0	939.0		
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(2,383.5)	(1,420.2)	(1,003.8)	(48.5)	(16.4)	(450.7)	12.5	0.0	(850.9)	(79.9)	1.5	(48.5)	11.5		
DR mods	(326.8)	(409.7)	(71.3)	(266.8)	(15.3)	(9.1)	14.8	(157.4)	282.3	79.0	(236.4)	(109.4)	(71.7)		
EE mods	204.3	66.1	118.3	(91.6)	1.3	33.8	1.4	(1.1)	10.1	(5.4)	(27.5)	(90.5)	15.1		
EFORd effect	1,058.9	(8.6)	28.3	78.9	(29.5)	(135.0)	(1.2)	29.1	(70.1)	(52.0)	560.4	42.3	24.2		
DR and EE effect	64.1	22.0	8.0	6.8	0.6	1.8	0.8	3.2	5.5	1.8	11.5	3.6	3.9		
Total internal capacity @ 01-Jun-19	200,065.5	77,278.5	35,500.1	13,526.0	1,732.7	6,953.2	3,891.1	6,947.0	12,229.6	2,613.1	27,811.1	4,166.4	12,223.1	3,957.7	3,979.1
Correction in resource modeling	0.0	0.0	0.0	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(939.0)	0.0	0.0
Adjusted internal capacity @ 01-Jun-19	200,065.5	77,278.5	35,500.1	13,526.0	1,735.0	6,953.2	3,891.1	6,947.0	12,229.6	2,613.1	27,811.1	4,166.4	11,284.1	3,957.7	3,979.1
New generation	3,532.2	1,059.7	59.7	0.0	37.5	0.0	0.0	0.0	870.0	0.0	0.0	0.0	0.0	0.0	3.4
Reactivated generation	5.3	1.3	1.3	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(2,318.8)	(2,031.3)	(2,033.3)	6.3	(0.9)	(1,022.0)	(312.8)	13.8	26.0	2.4	(12.2)	(7.5)	(1.6)	0.0	(1.6)
Generation winter cap mods	409.2	54.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	123.3	0.0	20.0	0.0	0.0
DR mods	(2,231.4)	(1,207.9)	(458.4)	(512.4)	(21.0)	(50.4)	(36.6)	(223.6)	(137.4)	(166.8)	27.3	(288.8)	(144.8)	48.9	102.4
EE mods	636.6	236.1	148.7	63.1	7.9	58.2	16.3	4.6	7.9	2.5	92.0	58.5	6.1	46.5	50.9
EFORd effect	1,027.6	599.1	(46.1)	361.0	(13.9)	(1.2)	(19.4)	351.5	(277.3)	77.2	329.8	11.1	(60.7)	(172.5)	44.3
DR and EE effect	11.4	3.5	1.4	1.2	0.1	0.4	0.1	0.4	0.6	0.0	2.8	0.8	0.8	0.2	0.0
Total internal capacity @ 01-Jun-20	201,137.6	75,993.2	33,173.4	13,445.2	1,744.7	5,939.5	3,538.7	7,093.7	12,719.4	2,528.4	28,374.1	3,940.5	11,103.9	3,880.8	4,178.5

Table 5-7 RPM reserve margin: June 1, 2016 to June 1, 2020[44 45]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM	
										Percent	ICAP (MW)
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2
01-Jun-17	163,871.2	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,219.9	24.1%	7.5%	10,522.1
01-Jun-18	168,841.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	179,752.6	28.7%	12.6%	17,589.9
01-Jun-19	166,715.0	154,510.0	12,559.0	0.0	141,951.0	16.6%	6.59%	178,476.6	25.7%	9.1%	12,961.7
01-Jun-20	163,399.0	153,915.0	12,200.6	558.0	141,156.4	16.6%	6.59%	174,926.7	23.9%	7.3%	10,338.3

42 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC, SWMAAC, and PPL. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco and BGE. ATSI includes ATSI Cleveland.

43 Unless otherwise specified, an annual equivalent MW quantity is used to report winter and summer capacity. For example, annual equivalent winter capacity is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

44 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

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

Demand

As shown in Table 5-10, there was a 787.1 MW decrease in the RPM reliability requirement from 180,332.2 MW on June 1, 2016, to 179,545.1 MW on June 1, 2017. 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 Forecast Pool Requirement (FPR) constant at the 2016/2017 level offset by a 230.3 MW increase attributable to the change in FPR.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2017 PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 63.6 percent (Table 5-8), down from 64.1 percent on June 1, 2016. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 36.4 percent, up from 35.9 percent on June 1, 2016. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007 to June 1, 2016 is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 63.6 percent on June 1, 2017. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 36.4 percent on June 1, 2017. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2017

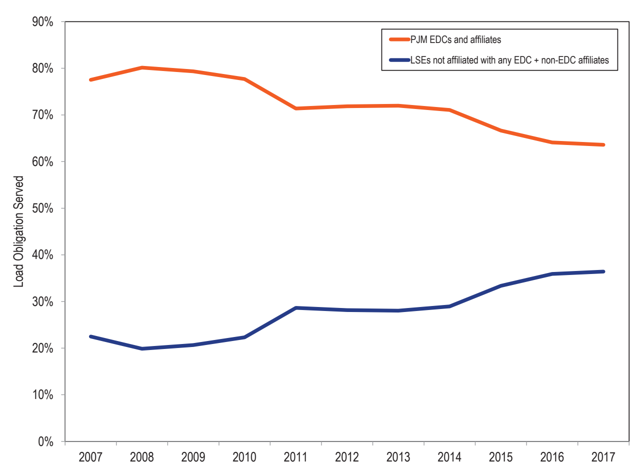


Table 5-8 Capacity market load obligation served: June 1, 2017

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	62,326.1	19,471.6	27,584.8	6,093.0	19,408.2	1,016.5	36,127.8	172,028.1
Percent of total obligation	36.2%	11.3%	16.0%	3.5%	11.3%	0.6%	21.0%	100.0%

Capacity Transfer Rights (CTRs)

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

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

In the 2020/2021 RPM Base Residual Auction, MAAC had -755.9 MW of CTRs with a total value of -$2,623,808, EMAAC had 4,748.3 MW of CTRs with a total value of $176,485,896, ComEd had 1,192.7 MW of CTRs with a total value of $48,579,473, and DEOK had 2,619.7 MW of CTRs with a total value of $51,127,157.[46] Credits for ICTRs in EMAAC totaled 948 MW with a total value of $35,235,217. DOEK has 155 MW of ICTRs with a total value of $3,025,065.

The negative CTRs for MAAC represent capacity that cleared inside MAAC that was assigned to load in the Rest of RTO. In the BRA, 65,817.9 MW cleared in the MAAC LDA. However the capacity obligation for MAAC LDA for the 2020/2021 delivery year was only 65,138.7 MW, 679.2 MW less than the cleared capacity.[47] The 679.2 MW that cleared in excess of the capacity obligation was assigned to load in Rest of RTO. There was also an additional 76.7 MW of grandfathered, outgoing CTRs for MAAC, bringing the total to -755.9 MW of CTRs. The outgoing CTRs are valued at the capacity price difference between MAAC and the RTO, which is negative. The clearing price in MAAC was $86.04 and the clearing price in RTO was $76.53.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2017/2018 RPM Third Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, 2019/2020 RPM Base Residual Auction, 2019/2020 RPM First Incremental Auction, and the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS).[48] In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the CP Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation 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, increased the market clearing price.[49] [50] [51]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent

46 A negative value indicates that the amount of capacity cleared in the MAAC LDA exceeded the UCAP obligation for the MAAC LDA.

47 In the BRA, 8,800 MW cleared as imports from MAAC to EMAAC LDA. But CTR allocations are based on PJM's calculated capacity obligations by LDA. The imports calculated using the capacity obligation were 5,761.4. The inconsistency is due to the mismatch between the cleared MW in the BRA and the allocation of the capacity obligation. The CTRs are based on the allocation of the capacity obligation to each LDA, which is derived using the LDA's peak load scaling factors.

48 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

49 See OATT Attachment DD § 6.5.

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

51 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).

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 MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS 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 (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx 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 RSIx 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.

Table 5-9 RSI results: 2017/2018 through 2020/2021 RPM Auctions[52]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2017/2018 Base Residual Auction				
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1
2017/2018 First Incremental Auction				
RTO	0.47	0.40	38	38
PSEG	0.00	0.00	1	1
2017/2018 Second Incremental Auction				
RTO	0.65	0.32	30	30
PSEG	0.00	0.00	0	0
PSEG North	0.00	0.00	0	0
2017/2018 Third Incremental Auction				
RTO	0.70	0.42	63	63
PSEG	0.00	0.00	0	0
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	-0.00	0.00	2	2
ComEd	0.00	0.00	1	1
2018/2019 Second Incremental Auction				
RTO	0.64	0.87	44	9
EMAAC	0.25	0.06	5	5
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1

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

Locational Deliverability Areas (LDAs)

Under the PJM 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 is 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 are modeled as potentially constrained LDAs regardless of the results of the above three tests.[53] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[54] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[55] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of PJM locational deliverability areas

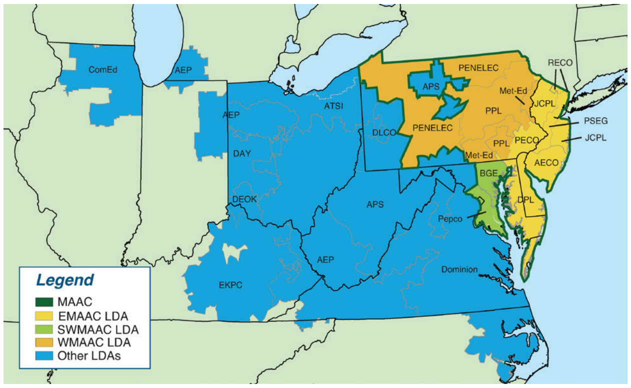


Figure 5-5 Map of PJM RPM EMAAC subzonal LDAs

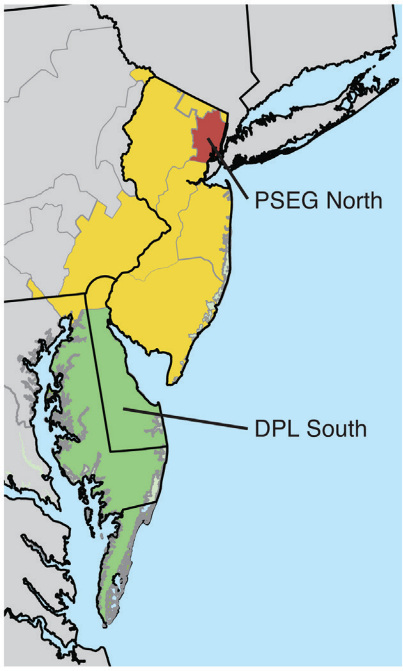
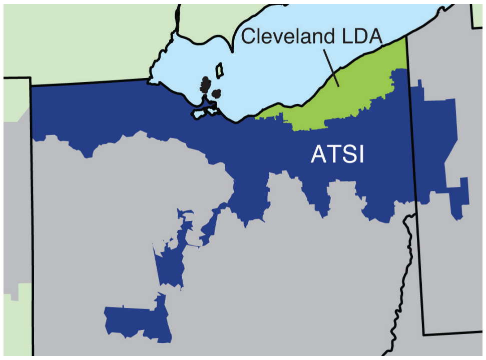


Figure 5-6 Map of PJM RPM ATSI subzonal LDA



53 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.
54 OATT Attachment DD § 5.10 (a) (ii).
55 146 FERC ¶ 61,052 (2014).

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[56]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. While pseudo ties were a step toward this goal, pseudo ties alone are not adequate to ensure deliverability. Pseudo ties create potential issues in the exporting area and do not ensure deliverability into the importing area. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 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.[57] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter.[58]

As shown in Table 5-10, net exchange decreased 2,069.6 MW from June 1, 2016 to June 1, 2017. Net exchange, which is imports less exports, decreased due to a decrease in imports of 2,086.7 MW offset by a decrease in exports of 17.1 MW.

As shown in Table 5-11, of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 percent) were from MISO.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[59] [60] Firm transmission service from the unit to the 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; 12 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 nonrecallability must be provided to assure PJM that the energy and capacity

56 OATT Attachment DD § 5.6.6(b).

57 147 FERC ¶ 61,060 (2014).

58 151 FERC ¶ 61,208 (2015).

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

60 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 54-55 & 81.

from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[61]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned external generation capacity resources are eligible to be offered into an RPM auction if they meet specific requirements.[62] [63] 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.[64] 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.[65]

Exporting Capacity

Nonfirm transmission can be used to export capacity from the PJM region. A generation capacity resource located in the PJM region not committed to service of PJM loads may be removed from PJM capacity resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[66] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[67]

The MMU evaluates requests submitted by Capacity Market Sellers to export generation capacity resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[68]

When submitting a real-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

61 OATT Schedule 1 § 1.10.1A.
62 See RAA § 1.69A.
63 See "PJM Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 57–58.
64 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).
65 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).
66 OATT Attachment DD § 6.6(g).
67 *Id.*
68 OATT Attachment M-Appendix § II.C.2.

Table 5-10 PJM capacity summary (MW): June 1, 2007, to June 1, 2020[69 70 71]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14	01-Jun-15	01-Jun-16	01-Jun-17	01-Jun-18	01-Jun-19	01-Jun-20
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4	217,829.1	216,671.5	208,605.9	210,712.9	213,519.5	213,713.4
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2	207,738.6	207,578.0	198,282.6	199,583.9	203,539.2	205,235.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9	167,305.9	165,109.2
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7	0.0	65.2	38.6	23.6	0.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5	177,184.1	180,332.2	179,545.1	174,896.8	171,036.8	167,644.2
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1	162,777.4	166,127.5	165,007.1	160,607.4	157,092.4	154,355.3
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3	5,855.9	7,185.4	6,187.0	6,268.1	8,722.0	9,043.7
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,055.5	4,395.5	7,941.5	5,854.8	5,603.4	4,762.3	5,390.7
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,228.1)	(1,214.2)	(1,211.6)	(1,194.5)	(1,282.3)	(1,288.6)	(1,293.3)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	2,827.4	3,181.3	6,729.9	4,660.3	4,321.1	3,473.7	4,097.4
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,677.1
EE cleared						568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,659.2
EE cleared (non annual equivalent)														1,710.2
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6									
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1	356.8	501.9	556.2	650.2	642.1	357.8
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2	4,125.2			

Table 5-11 RPM imports: 2007/2008 through 2020/2021 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2

Demand Resources

There are three basic demand products incorporated in the RPM market design:[72]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** 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 after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. 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.[73]

69 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 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. 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. For the 2018/2019 and subsequent delivery years, the net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement. For the 2019/2020 and subsequent delivery years, the net excess under RPM is calculated as cleared generation and DR capacity plus make whole MW less the reliability requirement. For the 2020/2021 and subsequent delivery years, the EE excluded from the supply side for this calculation includes annual EE and summer EE.

70 The results for RPM Incremental Auctions are not included in this table.

71 Unless otherwise specified, an annual equivalent MW quantity is used to report winter and summer capacity. For example, annual equivalent winter capacity is calculated as the winter capacity MW times the ratio of the number of days in the winter period (November through April of the delivery year) to the number of days in the delivery year.

72 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 into RPM auctions as capacity resources and receive the clearing price.

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

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of remand Resource products included in the RPM market design:[74 75]

- **Annual DR.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** A demand resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended summer DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** A demand resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[76 77]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

74 134 FERC ¶ 61,066 (2011).
75 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
76 151 FERC ¶ 61,208.
77 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

- Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.
- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-12, Table 5-13, and Table 5-14, capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity (3,675.2 MW).

Table 5-12 RPM load management statistics by LDA: June 1, 2016 to June 1, 2020[78 79 80 81]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
	DR cleared	13,265.3	5,398.0	2,017.5	1,622.6	105.7	622.6	227.1	683.9	1,841.4	470.8					
	EE cleared	1,723.2	418.0	86.4	262.6	2.0	27.9	10.8	136.5	226.9	58.6					
01-Jun-16	DR net replacements	(4,800.7)	(1,908.8)	(802.5)	(407.4)	(43.1)	(287.8)	(92.8)	(150.1)	(1,290.5)	(342.3)					
	EE net replacements	61.1	111.0	27.1	94.5	(0.6)	6.3	3.3	17.9	(79.0)	(15.4)					
	Total RPM load management	10,248.9	4,018.2	1,328.5	1,572.3	64.0	369.0	148.4	688.2	698.8	171.7					
	DR cleared	11,870.7	4,584.5	1,630.9	1,464.1	86.3	402.8	157.1	658.3	1,256.0	323.5	1,602.9	805.8	811.9		
	EE cleared	1,922.3	547.7	180.0	291.5	5.6	55.2	18.5	155.4	192.3	41.4	747.6	136.1	43.2		
01-Jun-17	DR net replacements	(3,870.8)	(1,461.6)	(555.7)	(344.8)	(39.5)	(107.9)	(30.6)	(136.5)	(457.2)	(163.1)	(279.2)	(208.3)	(299.2)		
	EE net replacements	195.6	145.8	20.6	98.3	(0.4)	4.4	2.6	26.2	(41.9)	(11.7)	10.3	72.1	(9.9)		
	Total RPM load management	10,117.8	3,816.4	1,275.8	1,509.1	52.0	354.5	147.6	703.4	949.2	190.1	2,081.6	805.7	546.0		
	DR cleared	11,275.8	4,339.4	1,700.6	1,210.5	86.8	389.9	139.2	550.5	964.0	287.2	1,895.2	660.0	716.2		
	EE cleared	1,785.9	526.7	211.9	261.3	5.4	59.9	18.7	155.6	90.0	16.8	762.7	105.7	32.0		
01-Jun-18	DR net replacements	(232.4)	(81.4)	(68.9)	0.0	0.0	(10.9)	0.0	0.0	(16.0)	0.0	(95.0)	0.0	0.0		
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	Total RPM load management	12,829.3	4,784.7	1,843.6	1,471.8	92.2	438.9	157.9	706.1	1,038.0	304.0	2,562.9	765.7	748.2		
	DR cleared	10,375.9	3,796.3	1,650.3	745.1	91.3	380.7	176.5	488.7	900.9	289.9	1,757.4	256.4	739.8		
	EE cleared	1,802.1	508.0	186.2	232.1	3.2	57.4	12.8	117.2	87.7	5.7	731.2	114.9	53.6		
01-Jun-19	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	Total RPM load management	12,178.0	4,304.3	1,836.5	977.2	94.5	438.1	189.3	605.9	988.6	295.6	2,488.6	371.3	793.4		
	DR cleared	7,820.4	2,699.0	1,114.8	458.4	72.6	327.7	141.4	211.9	688.7	168.9	1,512.9	246.5	579.9	164.6	152.8
	EE cleared	1,710.2	545.0	293.1	191.9	8.6	93.3	17.9	66.8	33.2	0.4	701.9	125.1	34.5	33.1	65.8
01-Jun-20	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total RPM load management	9,530.6	3,244.0	1,407.9	650.3	81.2	421.0	159.3	278.7	721.9	169.3	2,214.8	371.6	614.4	197.7	218.6

78 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

79 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

80 See OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

81 See OATT. Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments, replacement, and registrations for Demand Resources: June 1, 2007 to June 1, 2020[82] [83] [84]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,275.8	0.0	(232.4)	11,043.4	0.0	11,043.4	0.0	1.090	0.0
01-Jun-19	10,375.9	0.0	0.0	10,375.9	0.0	10,375.9	0.0	1.089	0.0
01-Jun-20	7,820.4	0.0	0.0	7,820.4	0.0	7,820.4	0.0	1.089	0.0

Table 5-14 RPM commitments and replacements for Energy Efficiency Resources: June 1, 2007 to June 1, 2020[85]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	1,785.9	0.0	0.0	1,785.9	0.0	1,785.9
01-Jun-19	1,802.1	0.0	0.0	1,802.1	0.0	1,802.1
01-Jun-20	1,710.2	0.0	0.0	1,710.2	0.0	1,710.2

82 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

83 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

84 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

85 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[86] [87] [88] For Base Capacity, offer caps are defined as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

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.[89] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges.[90] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[91]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[92] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to offer based on 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.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment hours (A) in the delivery year.[93]

86 See OATT Attachment DD § 6.5.

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

88 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).

89 OATT Attachment DD § 6.8 (b).

90 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

91 OATT Attachment DD § 6.8 (a).

92 151 FERC ¶ 61,208.

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

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment hours (PAH) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[94]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

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

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

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

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

The competitive offer of such a resource is:

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

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A}))$. Both the components are proportional to the expected number of performance assessment hours. If the expected number of performance assessment hours (*H*) is significantly lower than the value used to determine the non-performance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net non-performance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the first assumption, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is invalid. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or non-performance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment hours are lower than the value used to determine the non-performance charge rate, the default offer cap of Net CONE times B may overstate the competitive offer and the market seller offer cap.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[95] 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 which is used as a benchmark value in assessing the competitiveness of a sell offer, 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. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[96]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[97] 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

94 OATT Attachment DD § 10A (d).

95 135 FERC ¶ 61,022 (2011).

96 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).

97 143 FERC ¶ 61,090 (2013).

combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

2017/2018 RPM Base Residual Auction

As shown in Table 5-15, 1,202 generation resources submitted offers in the 2017/2018 RPM Base Residual Auction. Unit-specific offer caps were calculated for 131 generation resources (10.9 percent of all generation resources), of which 122 generation resources (10.1 percent) included an APIR component. The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values (33.3 percent). Of the 1,202 generation resources, 28 Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 637 generation resources were price takers (53.0 percent). Market power mitigation was applied to the sell offers for 39 generation resources, including 6,827.0 MW.

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-19, 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 to higher weighted average gross ACRs for combined cycle, combustion turbine, subcritical/supercritical coal, and other units. 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. The highest APIR for a technology ($281.82 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($863.76 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2017/2018 CP Transition Incremental Auction

All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.

2017/2018 RPM First Incremental Auction

As shown in Table 5-15, 118 generation resources submitted offers in the 2017/2018 RPM First Incremental Auction. The MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values, 17 were unit-specific offer caps with an APIR component (14.4 percent of all generation resources), six Planned Generation Capacity Resources had uncapped offers (5.1 percent), and the remaining 57 generation resources were price takers (48.3 percent). Market power mitigation was applied to the sell offers for six generation resources, including 26.1 MW.

2017/2018 RPM Second Incremental Auction

As shown in Table 5-15, 505 generation resources submitted offers in the 2017/2018 RPM Second Incremental Auction. The MMU calculated offer caps for 35 generation resources (36.8 percent), of which 15 were based on the technology specific default (proxy) ACR values and 20 were unit-specific offer caps (21.1 percent of all generation resources), of which 18 included an APIR component. Of the 95 generation resources, seven Planned Generation Capacity Resources had uncapped offers (7.4 percent), and the remaining 53 generation resources were price takers (55.8 percent). Market power mitigation was applied to the sell offers of four generation resources, including 157.0 MW.

2017/2018 RPM Third Incremental Auction

As shown in Table 5-15, 310 generation resources submitted offers in the 2017/2018 RPM Third Incremental Auction. The MMU calculated offer caps for nine generation resources (2.9 percent), of which five were based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.3 percent of all generation resources), of which four offer caps included an APIR component. Of the 310 generation resources, 306 did not request unit specific offer caps, of which 205 generation resources elected the offer cap option of 1.1 times the BRA clearing price, five were based on the default ACRs, three Planned Generation Capacity Resources had uncapped offers (1.0 percent), and 93 generation resources were price takers (30.0 percent). Market power mitigation was applied to the sell offers of five generation resources, including 34.5 MW.

2018/2019 RPM Base Residual Auction

As shown in Table 5-16, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent). Market power mitigation was applied to the Base Capacity sell offers of 18 generation capacity resources, including 3,271.9 MW

As shown in Table 5-16, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $406.58 per MW-day for Base Capacity Resources and $496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $321.80 per MW-day for Base Capacity Resources and $356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $281.13 per MW-day for Base Capacity Resources and $344.93 for Capacity Performance Resources. The maximum APIR effect ($1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $10.08 per MW-day for Capacity Performance Resources.

2018/2019 RPM First Incremental Auction

As shown in Table 5-16, 80 generation resources submitted Base Capacity offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 were based on the technology specific default (proxy) ACR values and 12 were unit-specific offer caps (15.0 percent of all generation resources), of which all of which included an APIR component. Of the 30 generation resources with Base Capacity offers, four Planned Generation Capacity Resources had uncapped offers (5.0 percent), and the remaining 46 generation resources were price takers (57.5 percent). Market power mitigation was applied to the Base Capacity sell offers of three generation resources, including 8.2 MW.

As shown in Table 5-16, 293 generation resources submitted Capacity Performance offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for nine generation resources (3.1 percent), all of which were unit-specific with an APIR component. Of the 293 generation resources, 261 generation resources had the B times net CONE offer cap (89.1 percent), seven Planned Generation Capacity Resources had uncapped offers (2.4 percent), one generation resource had an uncapped planned uprate plus B times net CONE offer cap for the existing portion of the unit (0.3 percent), and the remaining 15 generation resources were price takers (5.1 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2018/2019 RPM Second Incremental Auction

As shown in Table 5-16, 68 generation resources submitted Base Capacity offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (16.2 percent of all generation resources), of which all included an APIR component. Of the 68 generation resources with Base Capacity offers, six Planned Generation Capacity Resources had uncapped offers (8.8 percent), and the remaining 39 generation resources were price takers (57.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-16, 344 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for five generation resources (1.5 percent), all of which were unit-specific with an APIR component. Of the 344 generation resources, 327 generation resources had the B times net CONE offer cap (95.1 percent), four Planned Generation Capacity Resources had uncapped offers (1.2 percent), and the remaining eight generation resources were price takers (2.3 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Base Residual Auction

As shown in Table 5-17, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent of all generation resources), of which 34 included an APIR component. Of the 505 generation resources, nine Planned Generation Capacity Resources had uncapped offers (1.8 percent), and the remaining 284 generation resources were price takers (56.2 percent). Market power mitigation was applied to the Base Capacity sell offers of 34 generation resources, including 3,116.5 MW.

As shown in Table 5-17, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources (2.5 percent), all of which were unit-specific with an APIR component. Of the 1,003 generation resources, 888 generation resources had the B times net CONE offer cap (88.5 percent), 14 Planned Generation Capacity Resources had uncapped offers (1.4 percent), two generation resources had uncapped planned uprates plus B times net CONE offer cap for the existing portion of the units (0.2 percent), and the remaining 74 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of three generation resources, including 50.8 MW.

Of the 505 generation resources which submitted Base Capacity offers, 34 (6.7 percent) included an APIR component. Of the 1,003 generation resources which submitted Capacity Performance offers, 25 (2.5 percent) included an APIR component. As shown in Table 5-21, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources. The maximum APIR effect ($1,104.93 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

2019/2020 RPM First Incremental Auction

As shown in Table 5-17, 81 generation resources submitted Base Capacity offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (13.6 percent of all generation resources), of which all included an APIR component. Of the 81 generation resources with Base Capacity offers, the remaining 53 generation resources were price takers (65.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-17, 382 generation resources submitted Capacity Performance offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for seven generation resources (1.8 percent), of which six were unit-specific with an APIR component and one was based on the technology specific default (proxy) ACR value. Of the 382 generation resources, 362 generation resources had the B times net CONE offer cap (94.8 percent), one Planned Generation Capacity

Resource had an uncapped offer (0.3 percent), one generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit (0.3 percent), and the remaining 11 generation resources were price takers (2.9 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2020/2021 RPM Base Residual Auction

As shown in Table 5-18, 1,114 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Base Residual Auction. The MMU calculated offer caps for 14 generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for 14 generation resources (1.3 percent) including 11 generation resources (1.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,114 generation resources offered as Capacity Performance, 956 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 12 Planned Generation Capacity Resources had uncapped offers, 18 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, two generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit, while the remaining 112 generation resources were price takers. Market power mitigation was applied to the sell offers of zero generation resources, including 0.0 MW.

Of the 1,114 generation resources which submitted Capacity Performance offers, 14 (1.3 percent) included an APIR component. As shown in Table 5-22, the weighted average gross ACR for units with APIR was $498.15 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $209.18 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $235.67 per MW-day for Capacity Performance Resources. The maximum APIR effect ($464.71 per MW-day for Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.23 per MW-day for Capacity Performance Resources.

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 5-23, of the 12,171.0 ICAP MW of MOPR Competitive Entry Exemption requests for the 2020/2021 RPM Base Residual Auction, all requests were granted. Of the 3,301.2 MW offered for MOPR Screened Generation Resources in the 2020/2021 RPM Base Residual Auction, 2,646.7 MW cleared and 654.5 MW did not clear.

Table 5-15 ACR statistics: 2017/2018 RPM Auctions

	2017/2018 Base Residual Auction		2017/2018 First Incremental Auction		2017/2018 Second Incremental Auction		2017/2018 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	369	30.7%	36	30.5%	15	15.8%	5	1.6%
Unit specific ACR (APIR)	122	10.1%	17	14.4%	18	18.9%	4	1.3%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	4	0.3%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Opportunity cost input	5	0.4%	0	0.0%	2	2.1%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	205	66.1%
Uncapped planned uprate and default ACR	31	2.6%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and price taker	6	0.5%	2	1.7%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned generation resources	28	2.3%	6	5.1%	7	7.4%	3	1.0%
Existing generation resources as price takers	637	53.0%	57	48.3%	53	55.8%	93	30.0%
Total Generation Capacity Resources offered	1,202	100.0%	118	100.0%	95	100.0%	310	100.0%

Table 5-16 ACR statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction				2018/2019 First Incremental Auction				2018/2019 Second Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	164	34.7%	0	0.0%	18	22.5%	0	0.0%	12	17.6%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%	12	15.0%	8	2.7%	11	16.2%	5	1.5%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%	0	0	1	0.3%	0	0	0	0.0%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.5%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	881	88.8%	NA	NA	261	89.1%	NA	NA	327	95.1%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	2	0.4%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	6	0.6%	NA	NA	1	0.3%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	8	1.7%	15	1.5%	4	5.0%	7	2.4%	6	8.8%	4	1.2%
Existing generation resources as price takers	246	52.0%	54	5.4%	46	57.5%	15	5.1%	39	57.4%	8	2.3%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%	80	100.0%	293	100.0%	68	100.0%	344	100.0%

Table 5-17 ACR statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction				2019/2020 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%	17	21.0%	1	0.3%
Unit specific ACR (APIR)	34	6.7%	8	0.8%	11	13.6%	5	1.3%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%	0	0	1	0.3%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%	NA	NA	362	94.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	1	0.3%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	9	1.8%	14	1.4%	0	0.0%	1	0.3%
Existing generation resources as price takers	284	56.2%	74	7.4%	53	65.4%	11	2.9%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%	81	100.0%	382	100.0%

Table 5-18 ACR statistics: 2020/2021 RPM Auctions

	2020/2021 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	3	0.3%
Unit specific ACR (APIR and CPQR)	11	1.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	956	85.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	18	1.6%
Uncapped planned uprate and price taker	2	0.2%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	12	1.1%
Existing generation resources as price takers	112	10.1%
Total Generation Capacity Resources offered	1,114	100.0%

Table 5-19 APIR Statistics: 2017/2018 RPM Base Residual Auction[98]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
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

Table 5-20 APIR Statistics: 2018/2019 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$85.36	$197.45
Net revenues	$117.38	$131.61
Offer caps	$30.74	$65.83
APIR units		
ACR	$406.58	$496.37
Net revenues	$83.43	$139.25
Offer caps	$321.80	$356.54
APIR	$281.13	$344.93
CPQR	$0.00	$10.08
Maximum APIR effect	$1,051.98	$1,051.98

Table 5-21 APIR Statistics: 2019/2020 RPM Base Residual Auction

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

Table 5-22 APIR Statistics: 2020/2021 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)
Non-APIR units	
ACR	
Net revenues	
Offer caps	
APIR units	
ACR	$498.15
Net revenues	$277.52
Offer caps	$209.18
APIR	$235.67
CPQR	$0.23
Maximum APIR effect	$464.71

98 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 5-23 MOPR Statistics: 2017/2018 through 2020/2021 RPM Base Residual Auctions[99]

Base Residual Auction	Request Type	Requested ICAP (MW)	Granted ICAP (MW)	Offered ICAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)
2017/2018	Competitive Entry Exemption	12,405.1	12,405.1	5,786.3	5,573.1	4,737.5
2017/2018	Self-Supply Exemption	940.0	940.0	940.0	906.1	906.1
2017/2018	Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
2017/2018	Total	13,345.1	13,345.1	6,726.3	6,479.2	5,643.6
2018/2019	Competitive Entry Exemption	13,462.5	13,462.5	3,723.3	3,563.6	3,563.6
2018/2019	Self-Supply Exemption	0.0	0.0	0.0	0.0	0.0
2018/2019	Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
2018/2019	Total	13,462.5	13,462.5	3,723.3	3,563.6	3,563.6
2019/2020	Competitive Entry Exemption	12,270.0	12,270.0	4,671.0	4,515.1	3,561.7
2019/2020	Self-Supply Exemption	1,827.2	1,827.2	1,779.5	1,697.8	1,697.8
2019/2020	Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
2019/2020	Total	14,097.2	14,097.2	6,450.5	6,212.9	5,259.5
2020/2021	Competitive Entry Exemption	12,171.0	12,171.0	3,212.5	3,161.1	2,646.7
2020/2021	Self-Supply Exemption	0.0	0.0	0.0	0.0	0.0
2020/2021	Unit-Specific Exception	0.0	0.0	0.0	0.0	0.0
2020/2021	Total	12,171.0	12,171.0	3,212.5	3,161.1	2,646.7

Extended Minimum Offer Price Rule (MOPR-Ex)

MOPR-Ex is a simple and straightforward approach to ensuring that the impact of state subsidies on markets is limited and the impact on other states is limited and that there is a disincentive for such subsidies. MOPR-Ex, with exemptions for competitive entry, for self supply by cost of service utilities, for self supply by public power entities and for competitive RPS programs is a practical and narrowly targeted approach to protecting competitive wholesale power markets. MOPR-Ex is a defined modification to the current MOPR rather than an elimination of all MOPR rules as proposed by PJM. MOPR-Ex is a better way to maintain PJM markets than the PJM proposal to permit subsidized units to displace competitive units that could result in the capacity market becoming a residual market and that will negatively affect the incentives of new generation to enter the market. The PJM capacity market and PJM markets overall cannot function as markets if the capacity market is a residual market. The current design requires all capacity resources to offer and all load to buy capacity, except those companies that elect the FRR option and keep load and generation out of the capacity market.

MOPR Ex would apply to all existing and new resources, regardless of technology type, that will receive revenue outside of Market Revenue. Market Revenue is defined as revenue that is received under a tariff administered by PJM or other Regional Transmission System or Independent System Operator and regulated by the Commission. MOPR-Ex would require subsidized generation to offer at competitive levels in the PJM Capacity Market, thereby preserving the efficient market outcomes and accurate signals for entry and exit that are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions.

The rules governing the Self-Supply Exemption for non-public power entities and the Competitive Entry Exemption would be retained under MOPR-Ex.[100] The MMU proposes two additional MOPR exemptions, a public entity exemption and a renewable portfolio standard (RPS) exemption. A resource that will have a revenue source other than Market Revenue applicable to a forthcoming delivery year, and is not eligible for an exemption, will be required to offer into the PJM RPM auction at the MOPR offer price floor or at a level granted through the Unit Specific Exception process. The MOPR offer price floor is equal to the net CONE times B.

Public Entity Exemption

The public entity exemption would apply for a public power entity if (1) the long-term resource plans are consistent with its business model and such resource plans are intended to be balanced with its load obligations; (2) in any delivery year the total capacity owned and contracted by the public power entity is less than or equal to 600 MW greater than the entity's load obligation, and (3) the cost and revenue criteria for the

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

100 On July 17, 2017, the U.S. Court of Appeals issued an opinion that vacated, in part, two FERC orders, 143 FERC ¶61,090 and 153 FERC ¶61,066, that had conditionally accepted a PJM filing that revised the MOPR to include a self-supply exemption and a competitive entry exemption. As a result, the current RPM rules do not include a self-supply exemption or a competitive entry exemption; however, the MOPR-Ex rules are expected to be filed with FERC in 2018 and the MMU supports the inclusion of the self-supply exemption and the competitive entry exemption.

self-supply exemption are satisfied.[101] Any excess supply would be subject to the MOPR floor unless it qualifies for a unit specific exception, where excess supply is the MW amount of owned and contracted capacity in excess of the sum of the entity's load obligation and 600 MW.

RPS Exemption

The RPS exemption from MOPR would apply if the resource was procured in a program in compliance with a state mandated RPS program prior to December 31, 2018, or was based on a request for proposals (RFP) issued under a state mandated RPS program prior to December 31, 2018. Alternatively, resources that satisfy all of the following would be eligible for the RPS exemption:

- the resource complies with the requirements of a state mandated renewable portfolio standard or voluntary renewable portfolio standard;
- the terms of such program are competitive and non-discriminatory, meaning that (1) the program requires LSEs to procure a defined amount of renewable resources, (2) both new and existing resources may participate, (3) all suppliers of renewable resources may participate, (4) the requirements of the program are fully objective and transparent, (5) the program terms do not include selection criteria that could give preference to new or existing resources, (6) the program terms do not use indirect means to discriminate against new or existing capacity, (7) the program terms do not use any locational requirement, e.g. offshore wind, other than restricting imports from other states, and (8) the renewable characteristic is the only screen for participation in the program where renewable does not include coal, natural gas or nuclear thermal resources;
- if the program does not use an auction, the terms of such program: (1) are consistent with fair market value and standard industry practice and (2) provide that the price paid for renewable energy credits is determined by the contract terms between the seller and the buyer.
- if the program uses an auction either as a means of procuring renewable attributes to meet state requirements, or as a means to facilitate the procurement of renewable attributes by responsible LSEs, such auction must be competitive and non-discriminatory, meaning (1) winner(s) of auction based on lowest offer prices, (2) payments to winners based on auction clearing price, and (3) at least three nonaffiliated sellers participate.

Replacement Capacity[102]

Table 5-24 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2020. The 2018 through 2020 numbers are not final.

Table 5-24 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2020

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(626.1)	165,981.7
01-Jun-18	171,798.8	0.0	(1,011.8)	170,787.0	0.0	170,787.0
01-Jun-19	169,624.6	0.0	(1,107.5)	168,517.1	0.0	168,517.1
01-Jun-20	165,109.2	0.0	0.0	165,109.2	0.0	165,109.2

Market Performance

Figure 5-7 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-25 shows RPM clearing prices for all RPM auctions held through 2017.

101 Item (3) refers to the self-supply exemption as it existed prior to the opinion issued on July 17, 2017, by the U.S. Court of Appeals.

102 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

Figure 5-8 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through 2017. A summary of these weighted average prices is given in Table 5-26.

Table 5-27 shows RPM revenue by resource type for all RPM auctions held through 2017 with $7.5 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as “new/repower/reactivated” is a capacity resource addition since the implementation of RPM and is considered “new/repower/reactivated” for its initial offer and all its subsequent offers in RPM auctions.

Table 5-28 shows RPM revenue by calendar year for all RPM auctions held through 2017. In 2016, RPM revenue was $8.8 billion. In 2017, RPM revenue was $8.8 billion.

Table 5-29 shows the RPM annual charges to load. For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion. For the 2017/2018 Delivery Year, annual charges to load are $9.1 billion.

Table 5-25 Capacity market clearing prices: 2007/2008 through 2020/2021 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00

Table 5-25 Capacity market clearing prices: 2007/2008 through 2020/2021 RPM Auctions (continued)

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
2018/2019 Second Incremental Auction	Base Capacity	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Base Capacity DR/EE	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Capacity Performance	$50.00	$50.00	$50.00	$50.00	$80.02	$50.00	$80.02	$80.02	$80.02	$50.00	$50.00	$50.00	$50.00
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04

Table 5-26 Weighted average clearing prices by zone: 2017/2018 through 2020/2021

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2017/2018	2018/2019	2019/2020	2020/2021
RTO				
AEP	$140.03	$161.00	$96.03	$76.54
APS	$140.03	$161.00	$96.03	$76.54
ATSI	$138.22	$151.68	$96.48	$76.53
Cleveland	$138.43	$159.55	$96.35	$76.53
ComEd	$140.48	$207.32	$195.55	$188.13
DAY	$140.03	$161.00	$96.03	$76.54
DEOK	$140.03	$161.00	$96.03	$76.54
DLCO	$140.03	$161.00	$96.03	$76.54
Dominion	$140.03	$161.00	$96.03	$76.54
EKPC	$140.03	$161.00	$96.03	$76.54
MAAC				
EMAAC				
AECO	$137.20	$217.00	$114.30	$187.72
DPL	$137.20	$217.00	$114.30	$187.72
DPL South	$133.72	$218.65	$117.45	$187.87
JCPL	$137.20	$217.00	$114.30	$187.72
PECO	$137.20	$217.00	$114.30	$187.72
PSEG	$205.58	$218.93	$117.10	$187.75
PSEG North	$212.51	$222.39	$117.81	$187.87
RECO	$137.20	$217.00	$114.30	$187.72
SWMAAC				
BGE	$125.37	$143.22	$95.18	$85.94
Pepco	$133.34	$149.40	$91.94	$86.01
WMAAC				
Met-Ed	$139.32	$154.61	$97.15	$86.06
PENELEC	$139.32	$154.61	$97.15	$86.06
PPL	$136.20	$148.41	$96.29	$86.04

Table 5-27 RPM revenue by type: 2007/2008 through 2020/2021[103 104]

				Coal		Gas		Hydroelectric		Nuclear	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,624,067,951	$3,516,075	$209,490,444	$0	$996,085,233	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,112,880,414	$9,784,064	$287,838,147	$12,255	$1,322,601,837	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,548,801,710	$30,168,831	$364,731,344	$11,173	$1,517,723,628	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,823,632,390	$58,065,964	$442,410,730	$19,085	$1,799,258,125	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,717,850,463	$98,448,693	$278,529,660	$0	$1,079,386,338	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,096,304	$76,633,409	$179,117,374	$11,998	$762,719,550	$0
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,153,560,721	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,172,570,169	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,672,530,801	$535,039,154	$389,540,948	$15,478,144	$1,850,033,226	$0
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,212,974,257	$667,098,133	$283,613,426	$13,927,638	$1,483,759,630	$0
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,546,380,480	$984,733,791	$348,972,234	$15,219,121	$1,694,447,711	$0
2018/2019	$636,049,319	$96,609,059	$262,514,266	$2,632,098,014	$77,069,006	$2,977,175,919	$1,443,285,559	$414,573,552	$15,344,022	$1,990,827,045	$0
2019/2020	$372,486,674	$84,844,416	$124,519,680	$1,609,158,969	$47,528,002	$1,943,077,786	$1,057,018,794	$247,795,677	$6,208,824	$1,274,763,734	$0
2020/2021	$325,121,955	$87,314,763	$105,675,035	$1,274,487,087	$36,115,158	$2,073,983,594	$1,144,499,809	$208,893,366	$7,721,948	$1,413,162,803	$0

	Oil		Solar		Solid waste		Wind		
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$340,362,114	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$378,756,365	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$450,523,876	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$446,000,462	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$266,483,502	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$248,611,128	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$386,561,718	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$323,630,668	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$401,718,239	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$265,547,984	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$280,738,408	$3,888,126	$0	$10,899,883	$34,771,100	$9,036,976	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$343,333,510	$2,922,855	$0	$15,939,493	$38,078,648	$9,645,386	$1,166,553	$53,665,227	$11,010,297,432
2019/2020	$187,309,985	$1,723,692	$0	$11,594,905	$21,205,162	$5,326,702	$753,594	$45,510,662	$7,040,827,258
2020/2021	$214,430,999	$1,406,926	$0	$5,734,079	$26,917,827	$5,428,707	$25,124	$33,760,562	$6,964,679,740

Table 5-28 RPM revenue by calendar year: 2007 through 2021[105]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$137.69	176,742.6	366	$8,906,998,628
2017	$133.19	180,272.0	365	$8,763,578,112
2018	$161.36	174,981.4	365	$10,305,511,877
2019	$139.13	170,759.7	365	$8,671,712,815
2020	$114.67	166,963.8	366	$7,007,460,680
2021	$115.57	165,109.2	151	$2,881,278,468

103 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

104 The results for the ATSI Integration Auctions are not included in this table.

105 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-7 History of PJM capacity prices: 1999/2000 through 2020/2021[106]

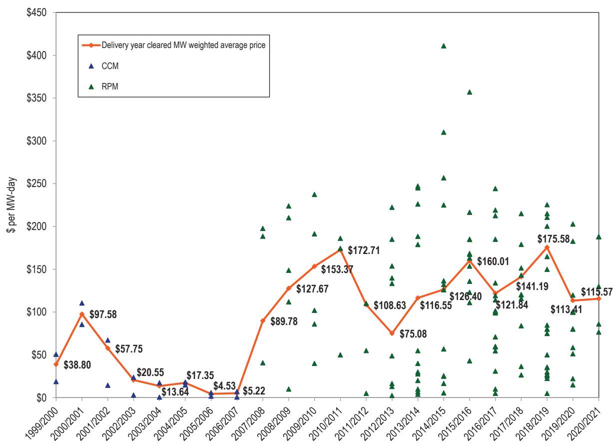
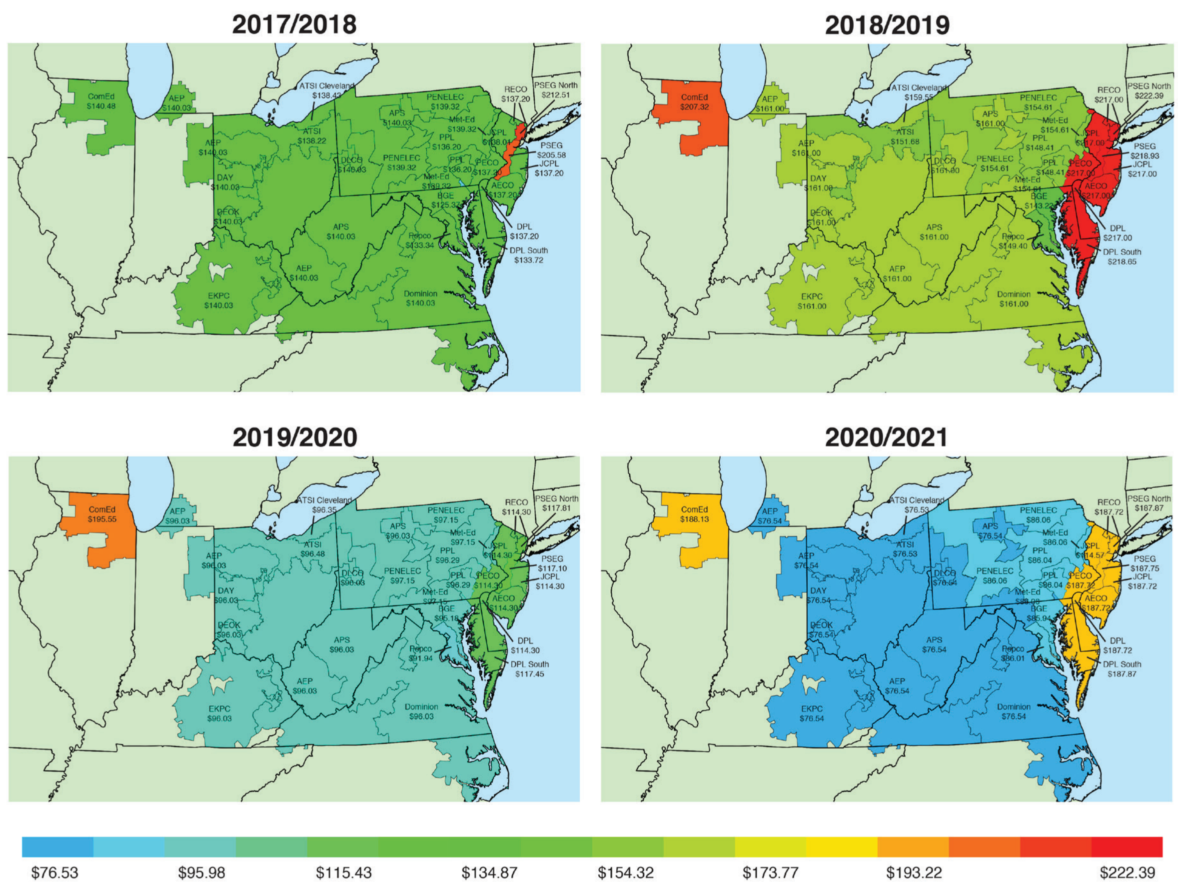


Figure 5-8 Map of RPM capacity prices: 2017/2018 through 2020/2021



106 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2020/2021 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by Delivery Year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent Delivery Years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Table 5-29 RPM cost to load: 2016/2017 through 2020/2021 RPM Auctions[107 108 109]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2016/2017			
Rest of RTO	$101.62	81,169.7	$3,010,600,585
Rest of MAAC	$163.27	52,594.4	$3,134,361,252
PSEG	$224.70	11,042.7	$905,665,239
ATSI	$133.23	14,084.2	$684,910,081
Total		158,891.0	$7,735,537,157
2017/2018			
Rest of RTO	$153.61	94,874.5	$5,319,445,392
Rest of MAAC	$153.74	44,352.0	$2,488,734,815
PSEG	$208.59	10,932.0	$832,333,767
PPL	$151.86	7,935.5	$439,869,055
Total		158,094.0	$9,080,383,029
2018/2019			
Rest of RTO	$164.68	80,744.7	$4,853,530,001
Rest of MAAC	$218.96	31,062.7	$2,482,513,646
BGE	$158.21	7,735.7	$446,719,430
DPL	$219.00	4,525.0	$362,693,243
ComEd	$211.92	24,800.0	$1,918,266,822
Pepco	$156.94	7,393.5	$423,512,918
PPL	$155.03	8,244.4	$466,513,972
Total		164,506.1	$10,953,750,032
2019/2020			
Rest of RTO	$97.61	89,604.4	$3,201,154,059
Rest of EMAAC	$115.15	24,335.4	$1,025,577,181
BGE	$97.73	7,676.6	$274,595,000
ComEd	$190.88	25,311.9	$1,768,321,123
Pepco	$92.47	7,381.5	$249,814,744
PSEG	$115.40	11,299.1	$477,218,187
Total		165,609.0	$6,996,680,295
2020/2021			
Rest of RTO	$76.83	69,612.5	$1,952,261,955.97
Rest of MAAC	$86.63	29,769.1	$941,266,092.93
Rest of EMAAC	$174.85	35,369.6	$2,257,334,820.17
ComEd	$183.14	25,153.0	$1,681,377,780.76
DEOK	$103.39	5,205.0	$196,428,322.59
Total		165,109.2	$7,028,668,972.43

107 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

108 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

109 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2018/2019, 2019/2020, and 2020/2021 Net Load Prices are not finalized. The 2018/2019, 2019/2020, and 2020/2021 obligation MW are not finalized.

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[110] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[111]

When notified of an intended deactivation, the Market Monitor performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[112] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[113] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[114] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[115] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[116] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[117]

110 OATT Part V.

111 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

112 OATT § 113.2; OATT Attachment M § IV.1.

113 OATT § 113.2.

114 *Id.*

115 OATT § 113.1.

116 OATT Attachment DD § 6.6(g).

117 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[118] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[119] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[120] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[121] Project investment is capped at $2 million, above which FERC approval is required.[122] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[123]

Table 5-30 shows units that have provided or are providing RMR service to PJM.

Table 5-30 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

118 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
119 OATT § 115.
120 *Id.*
121 OATT § 118.
122 OATT §§ 115, 117.
123 OATT § 119.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate.[124] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[125] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

124 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000.
125 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-31 shows the capacity factors by unit type for 2016 and 2017. In 2017, nuclear units had a capacity factor of 94.1 percent, compared to 91.3 percent in 2016; combined cycle units had a capacity factor of 58.4 percent in 2017, compared to a capacity factor of 62.0 percent in 2016; all steam units had a capacity factor of 40.7 percent in 2017, compared to 41.1 percent in 2016; coal units had a capacity factor of 46.6 percent in 2017, compared to 46.2 percent in 2016.

Table 5-31 PJM capacity factor (By unit type (GWh)): 2016 and 2017[126] [127]

	2016		2017		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2017 from 2016
Battery	15.7	0.6%	25.1	0.9%	0.3%
Combined Cycle	187,657.9	62.0%	195,631.7	58.4%	(3.6%)
Combustion Turbine	17,265.2	6.9%	13,390.7	5.3%	(1.6%)
Diesel	291.2	10.1%	359.5	11.1%	1.0%
Diesel (Landfill gas)	1,489.0	50.3%	1,642.2	50.5%	0.2%
Fuel Cell	227.6	86.4%	226.7	86.2%	(0.1%)
Nuclear	279,546.4	91.3%	287,575.8	94.1%	2.9%
Pumped Storage Hydro	6,077.2	13.7%	6,475.4	14.6%	0.9%
Run of River Hydro	7,609.6	31.4%	8,393.0	32.0%	0.6%
Solar	1,000.9	17.3%	1,463.1	17.0%	(0.2%)
Steam	293,624.9	41.1%	272,325.1	40.7%	(0.4%)
Coal	276,539.4	46.2%	258,498.3	46.6%	0.4%
Natural Gas	10,463.1	12.3%	7,770.3	9.2%	(3.0%)
Oil	258.4	1.3%	154.6	0.8%	(0.5%)
Biomass	6,364.0	64.0%	5,901.9	59.5%	(4.5%)
Wind	17,716.0	27.6%	20,714.1	29.5%	1.9%
Total	812,521.7	47.2%	808,222.4	47.0%	(0.2%)

Generator Performance Factors

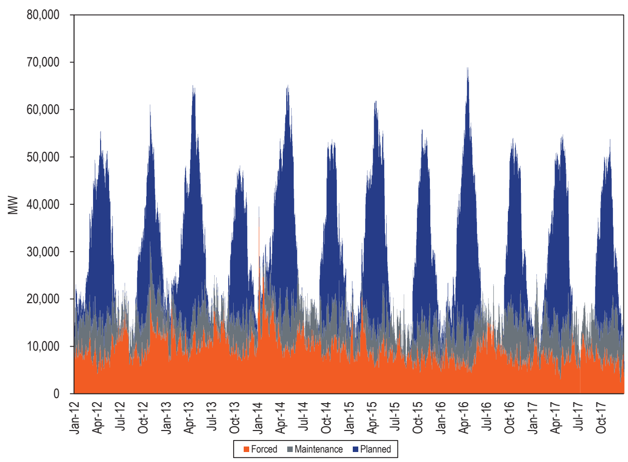
Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned

126 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

127 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-12.

Figure 5-9 PJM outages (MW): 2012 through 2017



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-10. Metrics by unit type are shown in Table 5-32.

Figure 5-10 PJM equivalent outage and availability factors: 2007 to 2017

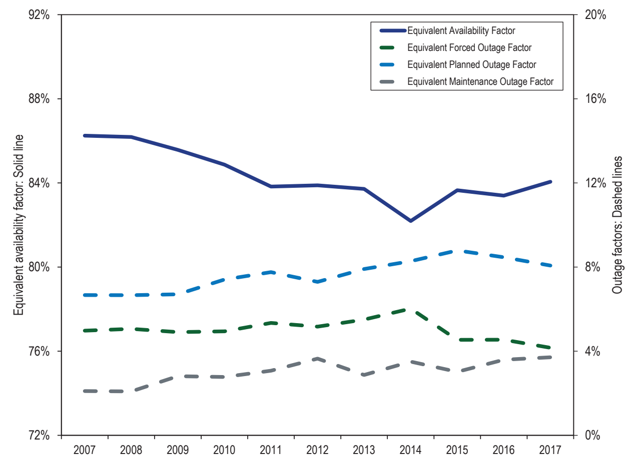


Table 5-32 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2017

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.7%	8.8%	2.7%	80.8%	2.3%	6.2%	2.0%	89.5%	4.6%	2.5%	2.6%	90.3%	10.2%	0.6%	1.6%	87.6%	1.3%	7.2%	1.4%	90.1%
2008	7.8%	7.6%	2.5%	82.1%	2.1%	5.9%	1.7%	90.3%	2.8%	4.1%	2.3%	90.8%	9.1%	1.0%	1.2%	88.7%	1.3%	7.8%	2.1%	88.8%
2009	6.8%	8.8%	3.6%	80.9%	2.7%	5.9%	3.1%	88.3%	1.4%	2.8%	2.4%	93.3%	6.6%	0.6%	1.1%	91.7%	2.3%	8.7%	2.3%	86.8%
2010	7.8%	9.3%	4.1%	78.9%	2.3%	8.1%	2.7%	86.9%	1.9%	2.9%	2.1%	93.1%	4.4%	0.4%	1.5%	93.6%	0.7%	8.6%	1.9%	88.8%
2011	8.3%	8.7%	4.4%	78.5%	2.4%	8.7%	2.3%	86.6%	2.1%	3.7%	2.4%	91.9%	3.3%	0.1%	1.8%	94.8%	1.7%	11.7%	1.9%	84.7%
2012	7.8%	8.4%	5.8%	77.9%	3.7%	8.3%	2.6%	85.5%	2.9%	3.2%	1.7%	92.2%	3.9%	0.7%	2.4%	93.1%	2.8%	6.3%	2.1%	88.9%
2013	8.7%	10.0%	4.4%	76.9%	2.4%	8.0%	2.4%	87.3%	5.1%	4.0%	1.7%	89.2%	6.0%	0.3%	1.4%	92.4%	2.3%	7.8%	1.9%	87.9%
2014	9.4%	9.2%	5.5%	75.9%	2.6%	10.1%	2.4%	84.8%	6.2%	3.9%	1.9%	88.0%	13.8%	0.4%	2.2%	83.5%	2.5%	9.3%	3.0%	85.3%
2015	7.7%	9.6%	4.5%	78.2%	2.2%	10.6%	2.2%	85.0%	2.8%	4.3%	2.4%	90.4%	7.6%	0.3%	2.7%	89.4%	3.7%	9.6%	1.5%	85.2%
2016	8.4%	8.9%	6.2%	76.5%	2.8%	10.6%	1.8%	84.9%	2.1%	5.4%	2.7%	89.8%	5.3%	0.2%	2.6%	92.0%	2.6%	7.7%	3.1%	86.6%
2017	9.0%	9.8%	7.0%	74.2%	1.9%	10.3%	1.6%	86.2%	1.3%	5.9%	2.0%	90.8%	5.3%	0.4%	2.1%	92.2%	2.1%	5.8%	3.2%	88.8%

	Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	5.3%	0.3%	93.1%	6.2%	7.6%	3.0%	83.3%
2008	1.8%	5.1%	0.8%	92.3%	8.7%	10.4%	3.1%	77.8%
2009	4.1%	5.2%	0.6%	90.1%	7.8%	7.4%	4.7%	80.1%
2010	2.3%	5.4%	0.5%	91.8%	8.2%	9.8%	3.5%	78.6%
2011	2.6%	6.1%	1.2%	90.1%	8.6%	11.1%	3.5%	76.9%
2012	1.5%	6.4%	1.1%	91.1%	8.1%	10.6%	4.8%	76.5%
2013	1.1%	5.9%	0.7%	92.2%	7.8%	10.5%	3.8%	77.9%
2014	1.8%	5.8%	0.9%	91.5%	7.1%	14.7%	5.4%	72.8%
2015	1.3%	5.5%	1.2%	91.9%	6.0%	17.5%	4.1%	72.4%
2016	1.7%	5.5%	1.2%	91.7%	4.7%	15.8%	4.4%	75.1%
2017	0.5%	5.1%	0.6%	93.7%	4.9%	9.8%	6.0%	79.4%

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[128] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2017 was 6.8 percent, an increase from 6.5 percent for 2016. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[129]

128 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

129 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2017 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2017

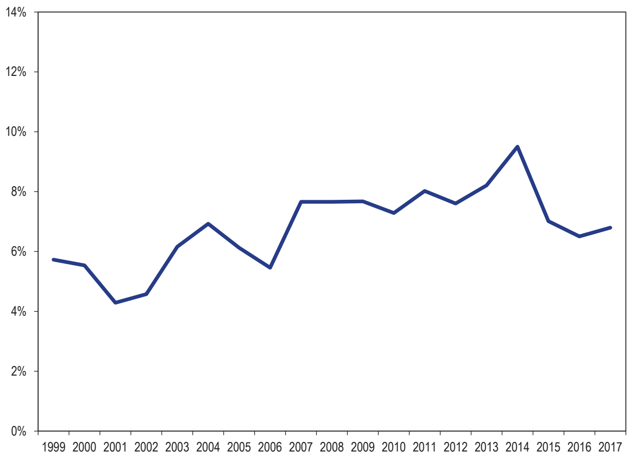


Table 5-33 shows the class average EFORd by unit type.

Table 5-33 PJM EFORd data for different unit types: 2007 through 2017

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Coal	8.8%	9.0%	8.4%	9.4%	10.6%	10.3%	11.1%	11.8%	9.4%	10.5%	12.0%
Combined Cycle	3.6%	3.4%	3.7%	3.0%	3.2%	4.4%	2.9%	4.4%	2.8%	3.5%	2.5%
Combustion Turbine	11.4%	11.2%	9.7%	9.1%	8.2%	8.5%	11.0%	15.9%	9.0%	6.0%	5.5%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.2%	6.4%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.6%	3.8%	5.2%	3.7%	2.8%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%	0.6%
Other	11.2%	15.6%	14.5%	12.4%	15.3%	12.3%	15.3%	14.2%	13.2%	9.3%	13.9%
Total	7.1%	7.7%	7.7%	7.3%	8.0%	7.6%	8.2%	9.5%	7.0%	6.5%	6.8%

Other Forced Outage Rate Metrics

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance capacity market design is implemented beginning with 2018/2019 Delivery Year but remain essential reasons why the incentive components of capacity performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the capacity performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the capacity performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours. Under the capacity performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

The current PJM capacity market rules create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the capacity performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 Delivery Year. Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[130]

Table 5-34 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 2.9 percent of all forced outages in 2017. The largest contributor to OMC outages, lack of fuel, was the cause of 33.4 percent of OMC outages and 1.0 percent of all forced outages.

Table 5-34 OMC outages: 2017

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Lack of fuel	33.4%	1.0%
Flood	21.2%	0.6%
Lightning	17.5%	0.5%
Switchyard system protection devices	6.4%	0.2%
Transmission line	5.3%	0.2%
Switchyard circuit breakers	3.8%	0.1%
Other switchyard equipment	3.1%	0.1%
Lack of water (hydro)	2.8%	0.1%
Transmission equipment beyond the 1st substation	2.2%	0.1%
Transmission system problems other than catastrophes	1.8%	0.1%
Transmission equipment	0.8%	0.0%
Other miscellaneous external problems	0.7%	0.0%
Wet coal	0.6%	0.0%
Switchyard transformers and associated cooling systems	0.2%	0.0%
Tornado	0.1%	0.0%
Storms	0.0%	0.0%
Other fuel quality problems	0.0%	0.0%
Total	100.0%	2.9%

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[131] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[132]

PJM EFOF was 4.2 percent in 2017. This means there was 4.2 percent lost availability because of forced outages. Table 5-35 shows that forced outages for boiler tube leaks, at 22.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

130 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

131 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

132 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-35 Contribution to EFOF by unit type by cause: 2017

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	28.1%	4.8%	0.0%	0.0%	0.0%	0.0%	18.9%	22.6%
Feedwater System	11.6%	1.1%	0.0%	0.0%	0.0%	1.1%	0.5%	8.5%
Electrical	5.6%	28.5%	10.5%	5.1%	3.2%	10.1%	3.2%	7.3%
Wet Scrubbers	8.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	6.2%
Boiler Air and Gas Systems	6.2%	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	4.9%
Low Pressure Turbine	5.9%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%
Exciter	1.1%	4.0%	1.6%	0.0%	12.7%	0.0%	23.6%	4.0%
Miscellaneous (Pollution Control Equipment)	4.1%	0.0%	4.2%	0.0%	0.0%	0.0%	3.3%	3.5%
Reserve Shutdown	1.2%	4.7%	14.1%	28.1%	17.9%	12.9%	4.8%	3.3%
Boiler Fuel Supply from Bunkers to Boiler	3.7%	0.4%	0.0%	0.0%	0.0%	0.0%	1.5%	2.8%
Miscellaneous (Generator)	1.3%	2.6%	3.4%	5.4%	17.0%	17.7%	1.0%	2.3%
Condensing System	2.6%	3.1%	0.0%	0.0%	0.0%	1.7%	0.5%	2.2%
Boiler Piping System	2.0%	3.3%	0.0%	0.0%	0.0%	0.0%	1.4%	1.8%
Valves	1.7%	0.7%	0.0%	0.0%	0.0%	5.9%	1.7%	1.6%
Economic	0.1%	1.6%	11.1%	5.3%	7.1%	0.0%	6.1%	1.6%
Auxiliary Systems	1.0%	3.2%	7.4%	0.0%	0.2%	2.6%	0.5%	1.4%
Generator	0.2%	7.0%	4.9%	5.8%	1.0%	4.1%	1.7%	1.2%
Controls	1.0%	2.8%	1.5%	1.0%	1.5%	5.1%	0.7%	1.2%
Boiler Fuel Supply to Bunker	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	8.5%	1.2%
All Other Causes	13.6%	31.8%	41.2%	49.2%	39.2%	38.8%	16.9%	18.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-36 shows the categories which are included in the economic category.[133] Lack of fuel that is considered outside management control accounted for 63.4 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[134] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-36 Contributions to Economic Outages: 2017

	Contribution to Economic Reasons
Lack of fuel (OMC)	62.9%
Lack of fuel (Non-OMC)	24.3%
Lack of water (hydro)	5.2%
Other economic problems	5.1%
Fuel conservation	1.1%
Ground water or other water supply problems	0.7%
Problems with primary fuel for units with secondary fuel operation	0.7%
Wet fuel (biomass)	0.3%
Total	100.0%

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

133 The definitions of these outages are defined by NERC GADS.
134 The definitions of these outages are defined by NERC GADS.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources. Under capacity performance, EFORp will not be used.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[135] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORp metric.

Table 5-37 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

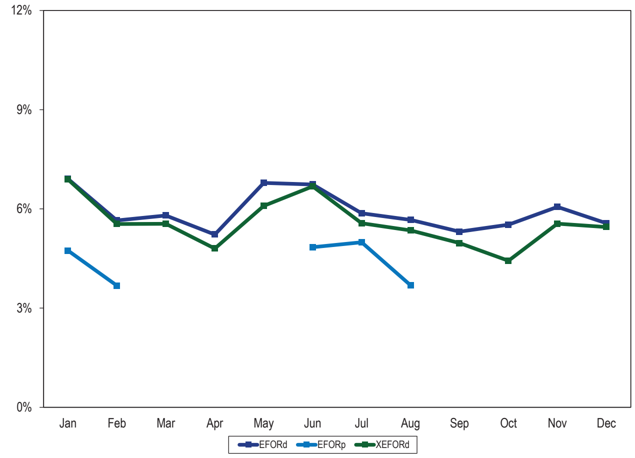
Table 5-37 PJM EFORd, XEFORd and EFORp data by unit type: 2017[136]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Coal	12.0%	12.0%	10.3%	0.1%	1.7%
Combined Cycle	2.5%	2.3%	1.2%	0.2%	1.3%
Combustion Turbine	5.5%	4.8%	2.4%	0.7%	3.1%
Diesel	6.4%	5.8%	3.8%	0.6%	2.6%
Hydroelectric	2.8%	2.8%	2.3%	0.0%	0.5%
Nuclear	0.6%	0.6%	1.0%	0.0%	(0.4%)
Other	13.9%	10.6%	3.9%	3.3%	10.0%
Total	6.8%	6.3%	4.7%	0.5%	2.1%

Performance by Month

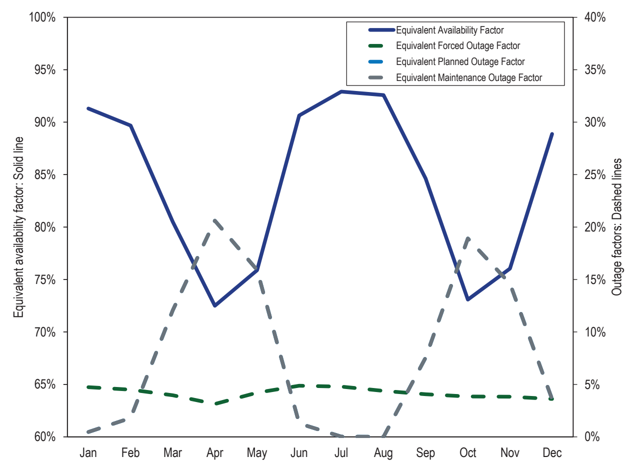
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 PJM EFORd, XEFORd and EFORp: 2017



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 PJM monthly generator performance factors: 2017



135 See "PJM Manual 22: Generator Resource Performance Indices," Rev. 17 (April 1, 2017), Definitions.

136 EFORp is only calculated for the peak months of January, February, June, July and August.