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 2016, 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. 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 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

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.

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.

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

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 Second Incremental Auction and the 2018/2019 RPM First Incremental Auction were conducted in the third quarter of 2016.

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 Non-Performance 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 2016, PJM installed capacity increased 4,766.3 MW or 2.7 percent, from 177,682.8 MW on January 1 to 182,449.1 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, 2016, 36.5 percent was coal; 35.7 percent was gas; 18.1 percent was nuclear; 3.7 percent was oil; 4.9 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year decreased 3,709.2 MW from 204,557.3 MW on June 1, 2015, to 200,848.1 MW on June 1, 2016. This decrease was the result of the integration of the East

7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2017) at 8.
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.

Kentucky Power Cooperative (EKPC) Zone resources (2,735.7 MW), new generation (5,517.4 MW), reactivated generation (751.8 MW), net generation capacity modifications (cap mods) (-3,373.3 MW), Demand Resource (DR) modifications (-10,690.1 MW), Energy Efficiency (EE) modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), and higher load management UCAP conversion factor (47.8 MW).

- **Demand.** There was a 3,148.1 MW increase in the RPM reliability requirement from 177,184.1 MW on June 1, 2015, to 180,332.2 MW on June 1, 2016. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2015/2016 level and a 711.3 MW increase attributable to the change in FPR. On June 1, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent, up from 65.1 percent on June 1, 2015.
- **Market Concentration.** In the 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2016/2017 RPM Third Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, and the 2019/2020 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 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,739.6 MW).

Market Conduct

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).
- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources which submitted offers in the 2016/2017 CP

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 (Reliability Pricing Model) § 5.10(a)(ii).

12 See PJM. 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 (2009) at P 30.

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).

Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

- **2016/2017 RPM Third Incremental Auction.** Of the 296 generation resources that submitted offers, the MMU calculated offer caps for 52 generation resources (17.6 percent), of which 35 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (5.7 percent).
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). 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.
- **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 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **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.
- **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 were unit-specific offer caps (11.2 percent). 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).
- **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 were unit-specific offer caps (8.1 percent). 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).

Market Performance

- The 2016/2017 RPM Third Incremental Auction, 2019/2020 RPM Base Residual Auction, the 2017/2018 RPM Second Incremental Auction, and 2018/2019 RPM First Incremental Auction were conducted in 2016. The weighted average capacity price for the 2017/2018 Delivery Year is $141.93 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through 2016. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through 2016. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through 2016. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $160.01 per MW-day in 2015/2016 and $121.84 per MW-day in 2016/2017.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2016 was 6.3 percent, a decrease from 7.0 percent for 2015.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2016 was 83.4 percent, a decrease from 83.6 percent for 2015.
- **Outages Deemed Outside Management Control (OMC).** In 2016, 4.0 percent of forced outages were classified as OMC outages, a decrease from 4.2 percent in 2015.

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]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. New recommendation. Status: Not adopted.)
- 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 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 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.)
- 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 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, 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

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 28, 2016. 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 *PJM Interconnection, L.L.C.*, 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, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

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 II, Section 6, Net Revenue.

of modeling assumptions.[22] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends the following changes with respect to capacity imports into PJM:
  - 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 as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported Q1, 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 improvements to the performance incentive requirements of RPM:
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted. Pending before FERC.)
- The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported Q3, 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all 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. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. 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 but did not when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that if PJM releases capacity in Incremental Auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sale price is not the BRA clearing price, PJM should not reveal its proposed sale price. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the requirement for First and Second Incremental Auctions and hold such auctions only if required based on increases in the Reliability Requirement above defined thresholds. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90

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).

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 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 they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially 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 that the definition of demand side resources be modified in order 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.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 as close to full substitutes for internal, physical capacity resources as possible. (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 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.)

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, but no exercise of market power in the PJM Capacity Market in 2016. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM capacity market results were competitive in 2016.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations

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, "Capacity in the PJM Market," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

to address those issues.[24 25 26 27 28] In 2015 and 2016, 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 Transition Incremental Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. 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 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 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 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 expanded 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

24 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

25 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).

26 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).

27 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).

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).

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, 2015 through 2016

Date	Name
January 14, 2015	IMM Comments re Capacity Performance Docket Nos. EL15-738-000 and EL15-739-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-738-000_EL15-739-000_20150114.pdf
January 20, 2015	IMM Comments re Capacity Performance Docket No. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-623-000_EL15-29-000_20150120.pdf
January 29, 2015	IMM Protest re IMEA Waiver Docket No. ER15-834-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-834-000_20150129.pdf
January 30, 2015	IMM Answer and Motion for Leave to Answer re Calpine Waiver Docket No. ER15-376-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_No_ER15-376-000_20150130.pdf
February 13, 2015	Comments of the Independent Market Monitor for PJM re DR in RPM Docket No. ER15-852-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-852-000_20150213.pdf
February 22, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150222.pdf
February 25, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150225.pdf
February 27, 2015	IMM Answer and Motion for Leave to Answer Errata re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Errata_Docket_Nos_ER15-623-000_EL15-29-000_20150227.pdf
March 6, 2015	IMM Comments re Champion Energy Complaint Docket No. EL15-46-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-46-000_20150306.pdf
March 20, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_ER15-623-000_EL15-29-000_20150320.pdf
March 25, 2015	IMM Protest re IMEA Waiver Docket No. ER15-1232-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-1232-000_20150325.pdf
March 26, 2015	IMM Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150326.pdf
April 15, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-001 and ER15-1470-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-001_ER15-1470-000_20150415.pdf
June 30, 2015	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_20150630.pdf
July 6, 2015	IMM Limited Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and El15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Limited_Request_for_Rehearing_Docket_Nos_ER15-623-000_001_and_20EL15-29-000_20150706.pdf
July 8, 2015	Intermittent Resources Capacity Performance Value Methodology http://www.monitoringanalytics.com/reports/Market_Messages/Messages/Intermittent_Resources_Capacity_Performance_Value_Methodology_20150708.pdf
July 20, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-004 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-004_EL15-29-000_20150720.pdf
July 31,2015	IMM Answer and Motion for Leave to Answer Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Request_for_Rehearing_Docket_No_ER15-623-000_001_EL15-29-000_20150731.pdf
September 11, 2015	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_20150911.pdf
November 4, 2015	IMM Comments re MISO Resources Docket Nos. EL15-70-000, EL15-71-000, EL15-72-000 and EL15-82-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_EL15-70-000_EL15-71-000_EL15-72-000_EL15-82-000_20151104.pdf
November 18, 2015	External Capacity: Pseudo Ties http://www.monitoringanalytics.com/reports/Presentations/2015/IMM_PJM_MISO_JCM_External_Capacity_Pseudo_Ties_20151118.pdf
November 30, 2015	IMM Comments re AEP Waiver Request Docket No. ER16-298-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER16-298-000_20151130.pdf
December 2, 2015	IMM Answer re AMEA Protest Docket No. ER15-623-000,-008 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_Docket_No_ER15-623-000_008_201512-2.pdf
December 23, 2015	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/RPM_Material/RPM_Must_Offer_Obligation_20151223.pdf
December 28, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re AEP Ohio Case Nos. 14-1693 EL-RDR and 14-1694 EL-AAM http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_AEP_Case_Nos_14-1693_14-1694_20151228.pdf
December 30, 2015	IMM First Supplemental Testimony of Joseph E. Bowring on Behalf of the Independent Market Monitor for PJM re FE Case No. 14-1297 EL-SSO http://www.monitoringanalytics.com/reports/Reports/2015/IMM_First_Supplemental_Testimony_of_Joseph_E_Bowring_14-1297_20151230.pdf
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

Table 5-2 RPM related MMU reports, 2015 through 2016 (continued)

Date	Name
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

Installed Capacity

On January 1, 2016, PJM installed capacity was 177,682.8 MW (Table 5-3).[29] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 182,449.1 MW on December 31, 2016, an increase of 4,766.3 MW or 2.7 percent from the January 1 level.[30 31] The 4,766.3 MW increase was the result of capacity modifications (421.2 MW), new or reactivated generation (5,421.4 MW), and an increase in imports (518.6 MW), offset by deactivations (706.0 MW), derates (197.7 MW), and an increase in exports (691.2 MW).

29 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.

30 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.

31 Wind resources accounted for 1,019.1 MW, and solar resources accounted for 262.3 MW of installed capacity in PJM on December 31, 2016. 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 (January 1, 2017) at 19.

At the beginning of the new delivery year on June 1, 2016, PJM installed capacity was 182,061.4 MW, an increase of 2,194.4 MW or 1.2 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, 2016, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2016.[32] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 36.6 percent on June 1, 2016 and is projected to decrease to 29.0 percent by June 1, 2019. The share of gas increased from 29.1 percent in 2007 to 35.6 percent in 2016, and is projected to increase to 45.8 percent in 2019.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2016

	1-Jan-16		31-May-16		1-Jun-16		31-Dec-16	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,674.8	37.5%	66,429.7	36.9%	66,619.9	36.6%	66,622.2	36.5%
Gas	60,487.4	34.0%	62,805.9	34.9%	64,721.7	35.5%	65,110.3	35.7%
Hydroelectric	8,787.5	4.9%	8,854.8	4.9%	8,850.4	4.9%	8,850.4	4.9%
Nuclear	33,071.5	18.6%	33,175.5	18.4%	33,050.6	18.2%	33,043.4	18.1%
Oil	6,851.8	3.9%	6,787.2	3.8%	6,779.8	3.7%	6,772.0	3.7%
Solar	128.0	0.1%	128.0	0.1%	252.4	0.1%	262.3	0.1%
Solid waste	769.4	0.4%	767.5	0.4%	767.5	0.4%	769.4	0.4%
Wind	912.4	0.5%	918.4	0.5%	1,019.1	0.6%	1,019.1	0.6%
Total	177,682.8	100.0%	179,867.0	100.0%	182,061.4	100.0%	182,449.1	100.0%

Figure 5-1 Percent of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2019

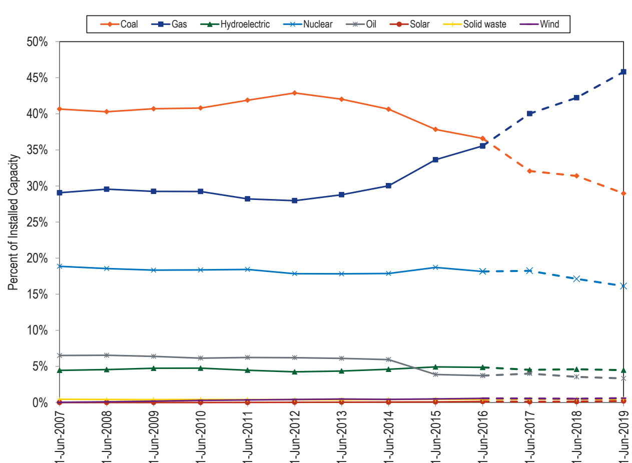


Figure 5-2 shows the fuel diversity index (FDI_c) for PJM installed capacity.[33]

The FDIc 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.[34] 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.[35] The FDI_c increased on average 0.1 percent from 2015 to 2016.

The FDI_c was used to measure the impact of potential retirements of coal and nuclear generators. The dotted line in Figure 5-2 shows the FDI_c calculated assuming that 3,000 MW of coal capacity and 3,000 MW of nuclear capacity were replaced by gas capacity in 2016. The FDI_c under the coal and nuclear retirement assumptions would have decreased the 2016 FDI_c by 0.9 percent.

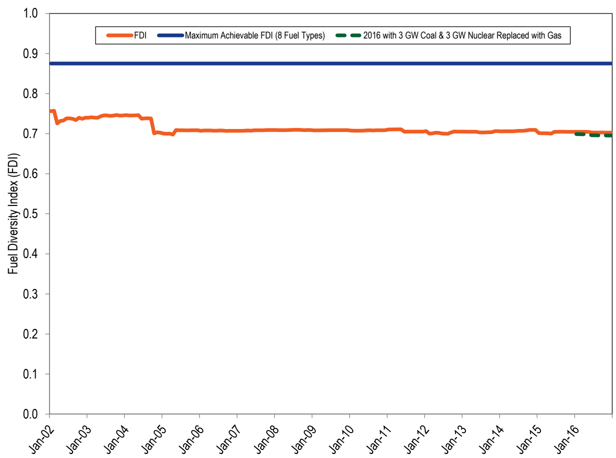
32 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

33 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.

34 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.

35 See the *2016 State of the Market Report for PJM*, Volume II, 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.

Figure 5-2 Fuel Diversity Index for PJM installed capacity (January 1, 2002 – January 1, 2017)



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.[36] In 2016, the 2016/2017 RPM Third Incremental Auction, 2019/2020 RPM Base Residual Auction, 2017/2018 RPM Second Incremental Auction, and 2018/2019 RPM First Incremental Auction were conducted.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2015/2016 Delivery Year. The 18,402.0 MW increase was the result of new generation capacity resources (15,284.9 MW), reactivated generation capacity resources (430.0 MW), uprates (5,510.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,998.3 MW), a net decrease in capacity exports (2,261.9 MW), offset by deactivations (26,122.3 MW) and derates (3,070.1 MW).

As shown in Table 5-5, total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year decreased 3,709.2 MW from 204,557.3 MW on June 1, 2015, to 200,848.1 MW on June 1, 2016. This increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone resources (2,735.7 MW), new generation (5,517.4 MW), reactivated generation (751.8 MW), net generation capacity modifications (cap mods) (-3,373.3 MW), Demand Resource (DR) modifications (-10,690.1 MW), Energy Efficiency (EE) modifications (262.5 MW), the EFORd effect due to lower sell offer EFORds (1,039.0 MW), and higher load management UCAP conversion factor (47.8 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2017/2018, 2018/2019, and 2019/2020 auctions, new generation were 15,353.3 MW; reactivated generation were 1,025.7 MW and net generation cap mods were -12,179.0 MW. DR and Energy Efficiency (EE) modifications totaled -2,698.7 MW through June 1, 2019. A decrease of 2,967.0 MW was due to lower EFORds, and an increase of 683.1 MW was due to a higher Load Management UCAP conversion factor. The net effect from June 1, 2016, through June 1, 2019, was a decrease in total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year of 782.6 MW (0.4 percent) from 200,848.1 MW to 200,065.5 MW.

As shown in Table 5-5 and Table 5-13, in the 2016/2017 auction, the 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource. The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1

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

MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW). The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW).

As shown in Table 5-5 and Table 5-14, 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 either exported or entirely committed to FRR for the 2017/2018 Delivery Year: one wind resource (26.0 MW). The 48 fewer generation resources offered consisted of 21 external resources not offered (2,630.4 MW), 18 deactivated resources (3,018.7 MW), three Planned Generation Capacity Resources not offered (1,171.7 MW), three resources excused from offering for reasons other than retirement (554.9 MW), two additional resources committed fully to FRR (168.3MW), and one resource that is no longer a PJM capacity resource (1.7 MW). In addition, there were retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2016/2017 BRA: 24 CT resources (964.4 MW) and 21 steam resources (2,716.2 MW).

As shown in Table 5-5 and Table 5-15, 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 5-5 and Table 5-16, 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).

Table 5-4 Generation capacity changes: 2007/2008 to 2016/2017

	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	787.3	285.1	825.0	158.3	5,425.7
2016/2017	182,061.4									
Total		15,284.9	430.0	5,510.3	18,109.0	5,998.3	(2,261.9)	26,122.3	3,070.1	18,402.0

Table 5-5 Internal capacity: June 1, 2015 to June 1, 2019[37]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5	3,484.3			
Integration of existing EKPC resources	2,735.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
New generation	5,517.4	2,291.3	606.5	3.6	0.0	30.2	0.0	0.0	767.1	0.0			
Reactivated generation	751.8	751.8	751.8	0.0	0.0	17.6	0.0	0.0	0.0	0.0			
Generation cap mods	(3,373.3)	(2,385.3)	(1,320.6)	(70.4)	(2.8)	(241.3)	(108.7)	0.0	(92.3)	0.0			
DR mods	(10,690.1)	(6,472.2)	(3,268.1)	(1,030.2)	(139.0)	(986.6)	(428.4)	(428.7)	(791.4)	564.7			
EE mods	262.5	145.6	28.7	85.6	0.7	3.2	0.7	50.4	131.0	55.7			
EFORd effect	1,039.0	575.2	160.5	325.3	6.8	(0.6)	(0.6)	146.4	(101.8)	(69.6)			
DR and EE effect	47.8	18.4	7.0	6.8	0.2	2.1	0.8	3.0	5.1	0.0			
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)	(1,421.4)	(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	77,277.3	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

37 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.

Demand

As shown in Table 5-8, there was a 3,148.1 MW increase in the RPM reliability requirement from 177,184.1 MW on June 1, 2015, to 180,332.2 MW on June 1, 2016. The 3,148.1 MW increase in the RTO Reliability Requirement was a result of a 2,436.8 MW increase in the forecast peak load in UCAP terms holding the FPR constant at the 2015/2016 level and a 711.3 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, 2016, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 67.8 percent (Table 5-6), up from 65.1 percent on June 1, 2015. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 32.2 percent, down from 34.9 percent on June 1, 2015. 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 67.8 percent on June 1, 2016. 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 32.2 percent on June 1, 2016. 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, 2016

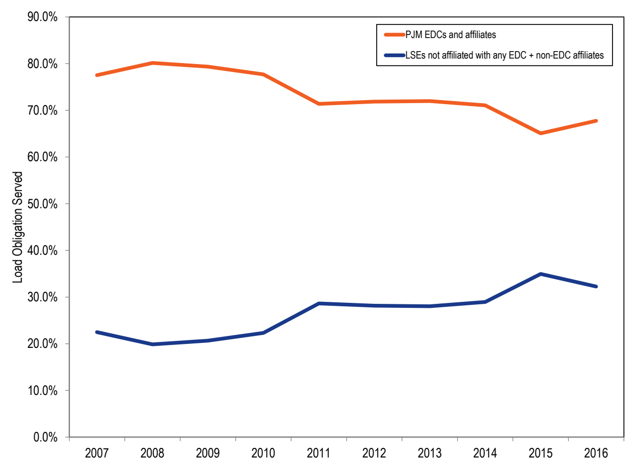


Table 5-6 Capacity market load obligations served: June 1, 2016

	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	53,042.9	23,917.9	5,835.4	4,624.2	5,560.2	1,820.9	27,401.2	122,202.6
Percent of total obligation	43.4%	19.6%	4.8%	3.8%	4.5%	1.5%	22.4%	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 equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2019/2020 RPM Base Residual Auction, EMAAC had 4,242.2 MW of CTRs with a total value of $30,695,796, ComEd had 2,355.1 MW of CTRs with a total value of $88,584,307, and BGE had 4,720.3 MW of CTRs with a total value of $518,289. Additionally, EMAAC had 898.0 MW of ICTRs with a total annualized value of $6,497,766, and BGE had 371.7 MW with a total annualized value of $33,599.

Market Concentration

Auction Market Structure

As shown in Table 5-7, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2016/2017 RPM Base Residual Auction, 2016/2017 RPM First Incremental Auction, 2016/2017 RPM Second Incremental Auction, 2016/2017 RPM Third Incremental Auction, 2017/2018 RPM Base Residual Auction, 2017/2018 RPM First Incremental Auction, 2017/2018 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2018/2019 RPM First Incremental Auction, and the 2019/2020 RPM Base Residual Auction.[38] The TPS test was not applied in the 2016/2017 CP Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. 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.[39] [40] [41] An overall offer cap was applied to all offers in the CP Transition Auctions.

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 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 5-7 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.

38 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.

39 See PJM. OATT Attachment DD § 6.5.

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

41 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).

Table 5-7 RSI results: 2016/2017 through 2019/2020 RPM Auctions[42]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2016/2017 Base Residual Auction				
RTO	0.78	0.59	110	110
MAAC	0.56	0.38	6	6
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 First Incremental Auction				
RTO	0.58	0.16	29	29
MAAC	0.26	0.00	3	3
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Second Incremental Auction				
RTO	0.63	0.37	32	32
PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 Third Incremental Auction				
RTO	0.54	0.35	64	64
MAAC	0.00	0.00	0	0
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
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
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
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

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.[43] 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."[44] 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.[45] 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.

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

43 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.

44 PJM. OATT Attachment DD § 5.10 (a) (ii).

45 146 FERC ¶ 61,052 (2014).

Figure 5-4 Map of PJM Locational Deliverability Areas

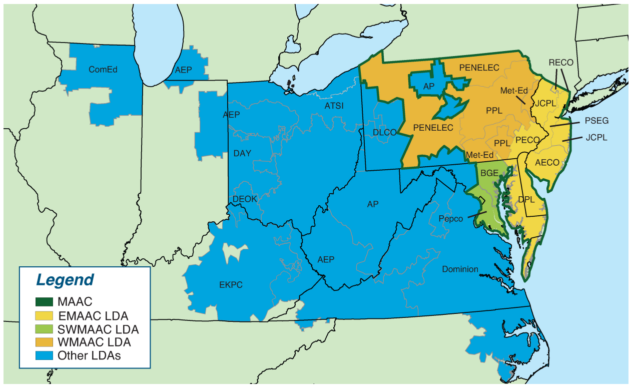


Figure 5-5 Map of PJM RPM EMAAC subzonal LDAs

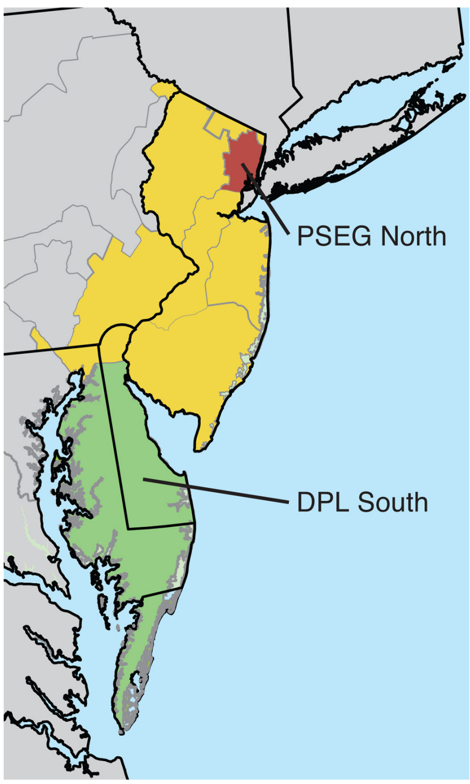
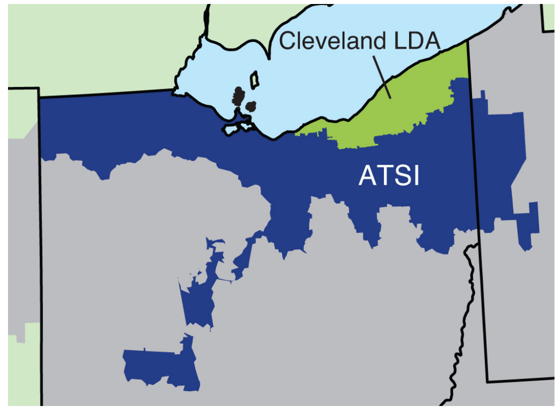


Figure 5-6 Map of PJM RPM ATSI subzonal LDA



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.[46]

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

46 PJM. OATT Attachment DD § 5.6.6(b).

Market should be clarified for both internal and external resources.

Effective with the 2017/2018 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[47] 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.[48]

As shown in Table 5-8, net exchange increased 3,548.6 MW from June 1, 2016 to June 1, 2016. Net exchange, which is imports less exports, increased due to an increase in imports of 3,546.0 MW and a decrease in exports of 2.6 MW.

As shown in Table 5-9, of the 4,343.4 MW of imports in the 2019/2020 RPM Base Residual Auction, 3,875.9 MW cleared. Of the cleared imports, 1,828.6 MW (47.2 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.[49] [50] 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; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of nonrecallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[51]

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.[52] [53] Planned External Generation

47 147 FERC ¶ 61,060 (2014).
48 151 FERC ¶ 61,208 (2015).
49 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
50 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 54-55 & 78-79.
51 OATT, Schedule 1, Section 1.10.1A.
52 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.
53 See "PJM Manual 18: PJM Capacity Market," Revision 36 (December 22, 2016) at 57-58.

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.[54] 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.[55]

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.[56] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[57]

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.[58]

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.

Table 5-8 PJM capacity summary (MW): June 1, 2007 to June 1, 2019[59 60]

	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
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
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
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
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
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
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
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
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
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)
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
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
EE cleared						568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1
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
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2	4,125.2		

54 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).

55 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).

56 OATT Attachment DD § 6.6(g).

57 *Id.*

58 OATT Attachment M-Appendix § II.C.2.

59 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.

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

Table 5-9 RPM imports: 2007/2008 through 2019/2020 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

Demand Resources

There are three basic demand products incorporated in the RPM market design:[61]

- **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.[62]

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of Demand Resource products included in the RPM market design:[63 64]

- **Annual DR.** A Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** A Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** 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:[65 66]

- **Base Capacity Demand Resource.** A Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Base Capacity Energy Efficiency Resource.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Base Capacity Energy

61 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.
62 Letter Order in Docket No. ER10-366-000 (January 22, 2010).
63 134 FERC ¶ 61,066 (2011).
64 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
65 151 FERC ¶ 61,208.
66 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

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

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

As shown in Table 5-10 and Table 5-12, capacity in the RPM load management programs was 10,248.9 MW for June 1, 2016, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2016/2017 Delivery Year (14,988.5 MW) less replacement capacity (4,739.6 MW). Table 5-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

Table 5-10 RPM load management statistics by LDA: June 1, 2015 to June 1, 2019[67 68 69 70]

		UCAP (MW)												
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
01-Jun-15	DR cleared	15,453.7	6,675.4	2,624.0	2,022.4	86.3	787.3	263.5	867.7	2,167.9				
01-Jun-15	EE cleared	1,189.6	279.0	73.1	164.8	3.1	26.4	11.5	59.3	142.0				
01-Jun-15	DR net replacements	(4,829.7)	(2,393.0)	(1,078.7)	(672.5)	(10.4)	(363.6)	(128.4)	(310.7)	(1,082.2)				
01-Jun-15	EE net replacements	335.9	230.4	48.5	149.2	0.0	12.4	2.7	61.1	15.2				
01-Jun-15	RPM load management	12,149.5	4,791.8	1,666.9	1,663.9	79.0	462.5	149.3	677.4	1,242.9				
01-Jun-16	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			
01-Jun-16	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)			
01-Jun-16	EE net replacements	61.1	111.0	27.1	94.5	(0.6)	6.3	3.3	17.9	(79.0)	(15.4)			
01-Jun-16	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			
01-Jun-17	DR cleared	11,735.2	4,577.2	1,623.6	1,464.1	86.3	402.8	157.1	658.3	1,127.8	309.0	1,602.9	805.8	811.9
01-Jun-17	EE cleared	1,844.1	509.6	154.0	280.3	4.9	36.4	10.3	150.8	176.0	41.3	736.8	129.5	42.6
01-Jun-17	DR net replacements	(322.0)	(215.0)	(113.0)	(18.0)	0.0	(2.0)	(2.0)	(6.0)	(48.0)	0.0	(28.0)	(12.0)	(39.0)
01-Jun-17	EE net replacements	(62.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(62.9)	(12.3)	0.0	0.0	0.0
01-Jun-17	RPM load management	13,194.4	4,871.8	1,664.6	1,726.4	91.2	437.2	165.4	803.1	1,192.9	338.0	2,311.7	923.3	815.5
01-Jun-18	DR cleared	11,200.6	4,302.1	1,690.7	1,183.1	86.8	389.9	139.2	523.1	958.6	287.2	1,895.2	660.0	716.2
01-Jun-18	EE cleared	1,579.8	443.3	170.7	225.2	3.5	44.4	10.9	125.1	67.6	13.9	753.8	100.1	28.9
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
01-Jun-18	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
01-Jun-18	RPM load management	12,548.0	4,664.0	1,792.5	1,408.3	90.3	423.4	150.1	648.2	1,010.2	301.1	2,554.0	760.1	745.1
01-Jun-19	DR cleared	10,348.0	3,777.1	1,636.5	739.7	91.3	380.7	176.5	483.3	897.6	289.9	1,757.4	256.4	739.8
01-Jun-19	EE cleared	1,515.1	426.9	160.8	179.7	1.0	49.3	8.4	79.0	41.0	0.2	724.8	100.7	50.9
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
01-Jun-19	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
01-Jun-19	RPM load management	11,863.1	4,204.0	1,797.3	919.4	92.3	430.0	184.9	562.3	938.6	290.1	2,482.2	357.1	790.7

Table 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2019/2020[71 72 73 74]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	14,337.6	14,943.0	1,035.4	1,077.7	0.0	0.0
2015/2016	14,891.6	15,453.7	1,147.7	1,189.6	0.0	0.0
2016/2017	12,737.6	13,265.3	1,656.9	1,723.2	0.0	0.0
2017/2018	11,299.9	11,735.2	1,777.2	1,844.1	0.0	0.0
2018/2019	10,292.1	11,200.6	1,452.2	1,579.8	0.0	0.0
2019/2020	9,510.3	10,348.0	1,393.7	1,515.1	0.0	0.0

67 See PJM. 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. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

68 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 include transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

69 See PJM. 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.

70 See PJM. 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.

71 For Delivery Years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

72 See PJM. 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. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

73 See PJM. 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.

74 See PJM. 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 5-12 RPM load management statistics: June 1, 2007 to June 1, 2019[75] [76]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	15,373.0	16,020.7	(6,458.4)	(6,731.8)	196.4	204.7	9,111.0	9,493.6
01-Jun-15	16,039.3	16,643.3	(4,653.7)	(4,829.7)	323.7	335.9	11,709.3	12,149.5
01-Jun-16	14,394.5	14,988.5	(4,609.3)	(4,800.7)	58.7	61.1	9,843.9	10,248.9
01-Jun-17	13,077.1	13,579.3	(310.0)	(322.0)	(60.6)	(62.9)	12,706.5	13,194.4
01-Jun-18	11,744.3	12,780.4	(213.5)	(232.4)	0.0	0.0	11,530.8	12,548.0
01-Jun-19	10,904.0	11,863.1	0.0	0.0	0.0	0.0	10,904.0	11,863.1

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.[77] [78] [79] 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.[80] 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.[81] 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.[82]

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).[83] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for

75 For Delivery Years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for Incremental Auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

76 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.

77 See OATT Attachment DD § 6.5.

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

79 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).

80 OATT Attachment DD § 6.8 (b).

81 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).

82 OATT Attachment DD § 6.8 (a).

83 151 FERC ¶ 61,208.

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.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[84] 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.[85]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[86] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen 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.

84 135 FERC ¶ 61,022 (2011).
85 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).
86 143 FERC ¶ 61,090 (2013).

2016/2017 RPM Base Residual Auction

As shown in Table 5-13, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 152 generation resources (12.7 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Of the 1,199 generation resources which submitted offers, 138 (11.5 percent) included an APIR component. As shown in Table 5-17, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units. The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA. The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($773.08 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2016/2017 RPM First Incremental Auction

As shown in Table 5-13, 115 generation resources submitted offers in the 2016/2017 RPM First Incremental Auction. Unit-specific offer caps were calculated for 37 generation resources (32.2 percent of all generation resources), of which 32 generation resources (27.8 percent) included an APIR component. The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values (21.7 percent). Of the 115 generation resources, one Planned Generation Capacity Resources had uncapped offers (0.9 percent), while the remaining 52 generation resources were price takers (45.2 percent). Market power mitigation was applied to the sell offers for four generation resources.

2016/2017 RPM Second Incremental Auction

As shown in Table 5-13, 101 generation resources submitted offers in the 2016/2017 RPM Second Incremental Auction. The MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent of all generation resources), of which 23 offer caps included an APIR component. Of the 101 generation resources, one Planned Generation Capacity Resource had an uncapped offer (1.0 percent), while the remaining 52 generation resources were price takers (51.5 percent). Market power mitigation was applied to the sell offers for two generation resources.

2016/2017 CP Transition Incremental Auction

All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.

2016/2017 RPM Third Incremental Auction

As shown in Table 5-13, 296 generation resources submitted offers in the 2016/2017 RPM Third Incremental Auction. The MMU calculated offer caps for 52 generation resources (17.6 percent), of which 35 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (5.7 percent of all generation resources), of which 17 offer caps included an APIR component. Of the 296 generation resources, 244 did not request unit specific offer caps, of which 145 generation resources elected the offer cap option of 1.1 times the BRA clearing price, 11 Planned Generation Capacity Resources had uncapped offers (3.7 percent), and 88 generation resources were price takers (29.7 percent). Market power mitigation was applied to the sell offers of zero generation resources.

2017/2018 RPM Base Residual Auction

As shown in Table 5-14, 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.

Of the 1,202 generation resources which submitted offers, 122 (10.1 percent) included an APIR component. As shown in Table 5-18, 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 5-14, 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.

2017/2018 RPM Second Incremental Auction

As shown in Table 5-14, 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.

2018/2019 RPM Base Residual Auction

As shown in Table 5-15, 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).

As shown in Table 5-15, 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). All offers were below the offer caps.

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 5-19, 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 5-15, 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 5-15, 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.

2019/2020 RPM Base Residual Auction

As shown in Table 5-16, 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 5-16, 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 5-20, 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.

Table 5-13 ACR statistics: 2016/2017 RPM Auctions

	2016/2017 Base Residual Auction		2016/2017 First Incremental Auction		2016/2017 Second Incremental Auction		2016/2017 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	471	39.3%	24	20.9%	17	16.8%	35	11.8%
Unit specific ACR (APIR)	138	11.5%	32	27.8%	23	22.8%	17	5.7%
Unit specific ACR (APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Unit specific ACR (non-APIR)	1	0.1%	4	3.5%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	NA	NA	NA	NA	NA	NA	NA	NA
Opportunity cost input	8	0.7%	1	0.9%	1	1.0%	0	0.0%
Default ACR and opportunity cost	5	0.4%	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	145	49.0%
Uncapped planned uprate and default ACR	15	1.3%	1	0.9%	4	4.0%	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	11	0.9%	0	0.0%	3	3.0%	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	31	2.6%	1	0.9%	1	1.0%	11	3.7%
Existing generation resources as price takers	519	43.3%	52	45.2%	52	51.5%	88	29.7%
Total Generation Capacity Resources offered	1,199	100.0%	115	100.0%	101	100.0%	296	100.0%

Table 5-14 ACR Statistics: 2017/2018 RPM Auctions

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

Table 5-15 ACR Statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction				2018/2019 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	164	34.7%	0	0.0%	18	22.5%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%	12	15.0%	8	2.7%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%	0	0	1	0.3%
Unit specific ACR (non-APIR)	1	0.2%	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	1.5%	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	881	88.8%	NA	NA	261	89.1%
Offer cap of 1.1 times BRA clearing price elected	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%
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	6	0.6%	NA	NA	1	0.3%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%	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
Uncapped planned generation resources	8	1.7%	15	1.5%	4	5.0%	7	2.4%
Existing generation resources as price takers	246	52.0%	54	5.4%	46	57.5%	15	5.1%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%	80	100.0%	293	100.0%

Table 5-16 ACR Statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction			
	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
Default ACR	171	33.9%	0	0.0%
Unit specific ACR (APIR)	34	6.7%	8	0.8%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	9	1.8%	14	1.4%
Existing generation resources as price takers	284	56.2%	74	7.4%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%

Table 5-17 APIR Statistics: 2016/2017 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$42.11	$33.46	$78.32	$215.57	$75.69	$102.23
Net revenues	$194.19	$56.23	$42.33	$208.04	$228.59	$150.24
Offer caps	$4.80	$7.64	$36.43	$29.03	$4.63	$16.07
APIR units						
ACR	$52.48	$93.23	$188.80	$432.72	$53.20	$352.84
Net revenues	$72.50	$17.49	$16.68	$222.52	$62.15	$177.14
Offer caps	$13.92	$79.12	$167.29	$213.88	$5.91	$180.23
APIR	$14.45	$57.71	$64.90	$236.99	$23.01	$191.19
Maximum APIR effect						$773.08

Table 5-18 APIR Statistics: 2017/2018 RPM Base Residual Auction

	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 5-19 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 5-20 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

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 5-21 shows RPM clearing prices for all RPM Auctions held through 2016.

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 2016. A summary of these weighted average prices is given in Table 5-22.

Table 5-23 shows RPM revenue by resource type for all RPM Auctions held through 2016 with $6.3 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 5-24 shows RPM revenue by calendar year for all RPM Auctions held through 2016. In 2015, RPM revenue was $9.0 billion. In 2016, RPM revenue was $8.9 billion.

Table 5-25 shows the RPM annual charges to load. For the 2015/2016 Delivery Year, RPM annual charges to load are $9.6 billion. For the 2016/2017 Delivery Year, annual charges to load are $7.7 billion.

Table 5-21 Capacity prices: 2007/2008 through 2019/2020 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
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
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

Table 5-21 Capacity prices: 2007/2008 through 2019/2020 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
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
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

Table 5-22 Weighted average clearing prices by zone: 2016/2017 through 2019/2020

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2016/2017	2017/2018	2018/2019	2019/2020
RTO				
AEP	$115.27	$140.42	$162.19	$96.60
AP	$115.27	$140.42	$162.19	$96.60
ATSI	$122.15	$139.84	$152.87	$97.03
Cleveland	$112.13	$139.01	$161.42	$97.44
ComEd	$115.27	$140.97	$209.55	$200.02
DAY	$115.27	$140.42	$162.19	$96.60
DEOK	$115.27	$140.42	$162.19	$96.60
DLCO	$115.27	$140.42	$162.19	$96.60
Dominion	$115.27	$140.42	$162.19	$96.60
EKPC	$115.27	$140.42	$162.19	$96.60
MAAC				
EMAAC				
AECO	$123.01	$138.01	$219.98	$114.57
DPL	$123.01	$138.01	$219.98	$114.57
DPL South	$119.87	$136.06	$219.21	$118.10
JCPL	$123.01	$138.01	$219.98	$114.57
PECO	$123.01	$138.01	$219.98	$114.57
PSEG	$220.70	$208.66	$220.71	$117.49
PSEG North	$218.25	$214.38	$223.42	$118.46
RECO	$123.01	$138.01	$219.98	$114.57
SWMAAC				
BGE	$120.96	$130.11	$143.38	$95.92
Pepco	$118.60	$134.81	$151.84	$92.25
WMAAC				
Met-Ed	$122.13	$140.03	$155.64	$98.04
PENELEC	$122.13	$140.03	$155.64	$98.04
PPL	$122.13	$136.45	$153.51	$97.03

Table 5-23 RPM revenue by type: 2007/2008 through 2019/2020[87] [88]

				Coal		Gas		Hydroelectric	
	Demand Resources	Energy Efficiency Resources	Imports	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	$1,624,111,360	$3,472,667	$209,490,444	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,112,913,366	$9,751,112	$287,850,403	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,548,801,710	$30,168,831	$364,742,517	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,823,632,390	$58,065,964	$442,429,815	$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
2012/2013	$264,387,898	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,096,304	$76,633,409	$179,117,975	$11,397
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
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
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
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
2017/2018	$513,340,753	$84,562,120	$218,558,934	$2,447,293,628	$62,716,892	$2,538,564,397	$983,815,482	$346,315,522	$15,183,161
2018/2019	$635,787,176	$92,912,038	$262,439,441	$2,622,702,914	$76,339,006	$2,966,354,301	$1,440,327,407	$414,573,552	$15,344,022
2019/2020	$372,297,036	$79,809,657	$124,354,356	$1,589,569,993	$47,528,002	$1,942,148,285	$1,056,052,247	$247,708,445	$6,208,824

	Nuclear		Oil		Solar		Solid waste	
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$996,085,233	$0	$340,362,114	$0	$0	$0	$31,512,230	$0
2008/2009	$1,322,601,837	$0	$378,756,365	$4,837,523	$0	$0	$35,011,991	$0
2009/2010	$1,517,723,628	$0	$450,523,876	$5,676,582	$0	$0	$42,758,762	$523,739
2010/2011	$1,799,258,125	$0	$446,000,462	$4,339,539	$0	$0	$40,731,606	$413,503
2011/2012	$1,079,386,338	$0	$266,483,502	$967,887	$0	$66,978	$25,636,836	$261,690
2012/2013	$762,719,551	$0	$248,611,128	$2,772,987	$0	$1,246,337	$26,840,670	$316,420
2013/2014	$1,346,223,419	$0	$386,561,718	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705
2014/2015	$1,464,950,862	$0	$323,630,668	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533
2015/2016	$1,850,033,226	$0	$401,718,239	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607
2016/2017	$1,483,759,630	$0	$265,547,984	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604
2017/2018	$1,692,710,933	$0	$279,435,824	$3,888,126	$0	$9,531,809	$34,350,458	$9,009,006
2018/2019	$1,979,780,844	$0	$342,162,298	$2,922,855	$0	$14,933,887	$37,917,294	$9,645,386
2019/2020	$1,262,041,327	$0	$187,212,812	$1,723,692	$0	$11,167,534	$21,032,486	$5,299,864

	Wind		
	Existing	New/repower/ reactivated	Total revenue
2007/2008	$430,065	$0	$4,252,287,381
2008/2009	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$812,644	$5,052,036	$3,871,714,635
2013/2014	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$1,300,167	$39,886,653	$9,280,463,863
2018/2019	$1,166,553	$53,365,379	$10,968,674,353
2019/2020	$752,496	$44,986,052	$6,999,893,108

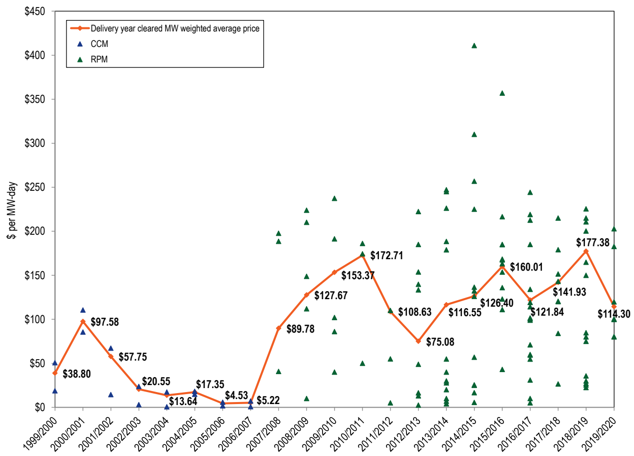
87 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

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

Table 5-24 RPM revenue by calendar year: 2007 through 2020[89]

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	$133.62	179,368.7	365	$8,748,209,479
2018	$162.71	172,927.6	365	$10,270,263,986
2019	$140.39	168,422.6	365	$8,630,559,230
2020	$114.30	167,329.5	152	$2,907,059,433

Figure 5-7 History of PJM capacity prices: 1999/2000 through 2019/2020[90]



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

90 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2019/2020 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.

Figure 5-8 Map of RPM capacity prices: 2016/2017 through 2019/2020

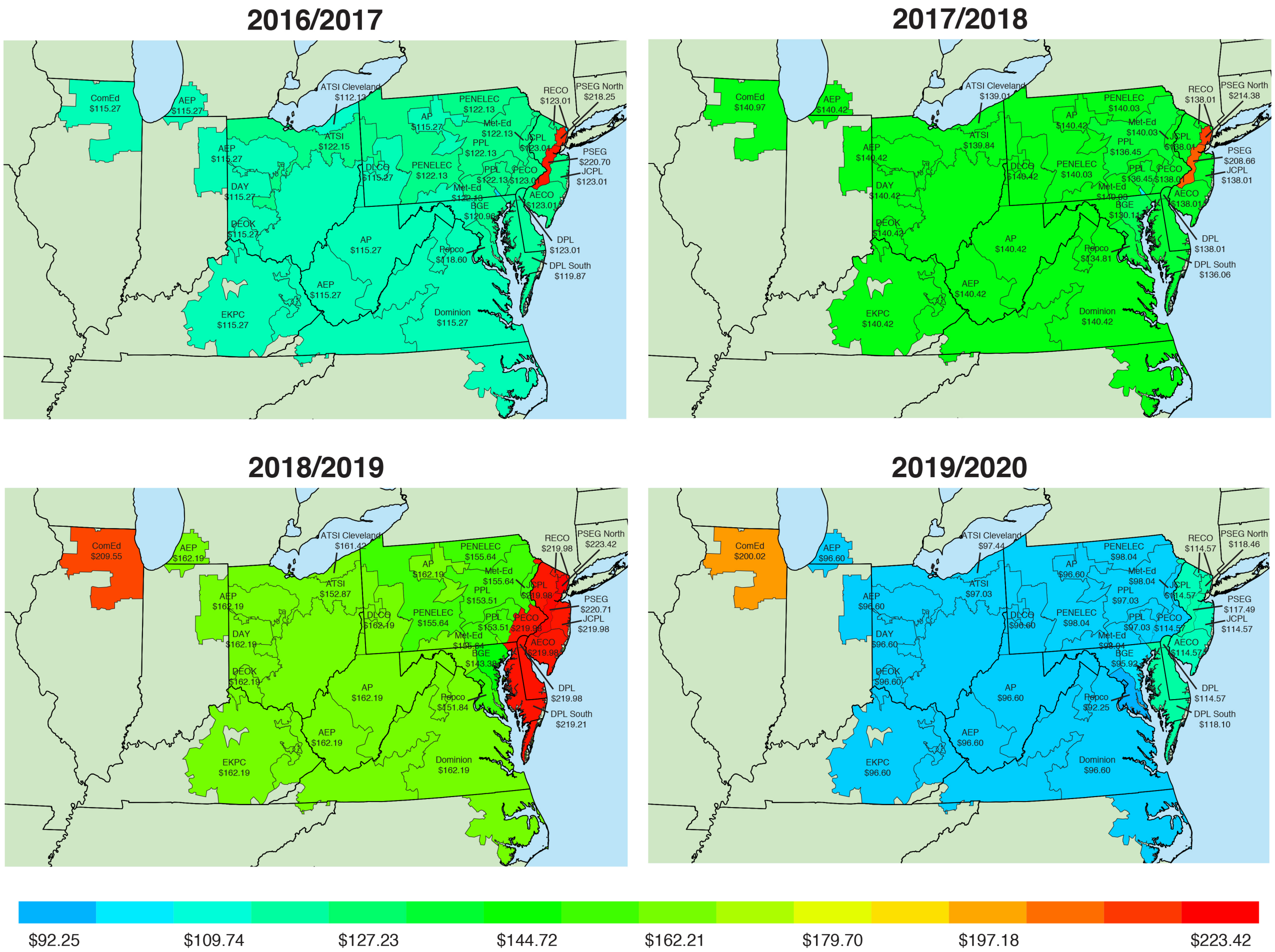


Table 5-25 RPM cost to load: 2015/2016 through 2019/2020 RPM Auctions[91][92][93]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2015/2016			
Rest of RTO	$135.81	81,984.4	$4,075,305,460
Rest of MAAC	$166.53	53,819.9	$3,280,332,235
PSEG	$166.29	11,398.1	$693,698,017
ATSI	$293.00	14,631.7	$1,569,095,567
Total		161,834.1	$9,618,431,279
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	$151.26	97,894.4	$5,404,664,473
Rest of MAAC	$151.38	45,679.7	$2,523,928,434
PSEG	$206.31	11,295.9	$850,620,887
PPL	$149.58	8,266.1	$451,307,271
Total		163,136.1	$9,230,521,064
2018/2019			
Rest of RTO	$162.30	75,583.6	$4,477,496,562
Rest of MAAC	$216.11	42,763.4	$3,373,215,391
BGE	$155.91	7,897.7	$449,426,120
ComEd	$209.32	24,909.7	$1,903,172,638
Pepco	$154.63	7,416.8	$418,613,355
PPL	$152.87	8,445.3	$471,233,226
Total		167,016.4	$11,093,157,292
2019/2020			
Rest of RTO	$96.77	90,810.6	$3,216,399,297
Rest of EMAAC	$114.21	24,500.3	$1,024,120,622
BGE	$96.89	7,831.5	$277,722,332
ComEd	$189.99	25,326.5	$1,761,076,090
Pepco	$91.64	7,401.5	$248,261,480
PSEG	$114.46	11,435.5	$479,041,445
		167,305.9	$7,006,621,266

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

92 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.

93 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 2017/2018, 2018/2019, and 2019/2020 Net Load Prices are not finalized. The 2017/2018, 2018/2019, and 2019/2020 obligation MW are not finalized.

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. In 2016, nuclear units had a capacity factor of 93.0 percent, compared to 94.5 percent in 2015; combined cycle units had a capacity factor of 62.0 percent in 2016, compared to a capacity factor of 62.5 percent in 2015; and steam units, which are primarily coal fired, had a capacity factor of 32.5 percent in 2016, compared to 43.8 percent in 2015. The decline in the capacity factor for coal units is the result of its higher operating costs compared to combined cycle and combustion turbine units in 2016.

Table 5-26 PJM capacity factor (By unit type (GWh)): January through December, 2015 and 2016[94]

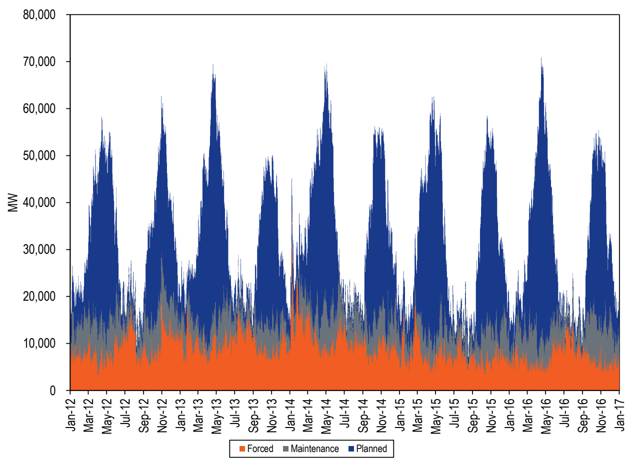
	2015		2016		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2016 from 2015
Battery	7.6	0.5%	15.7	0.6%	0.1%
Combined Cycle	159,420.8	62.5%	187,368.5	62.0%	(0.5%)
Combustion Turbine	14,213.8	5.6%	17,980.5	6.8%	1.2%
Diesel	578.9	15.2%	662.7	16.9%	1.7%
Diesel (Landfill gas)	1,508.6	45.6%	1,501.9	45.1%	(0.4%)
Fuel Cell	227.1	86.4%	227.6	86.4%	(0.0%)
Nuclear	279,106.5	94.5%	279,546.4	93.0%	(1.4%)
Pumped Storage Hydro	6,038.4	12.8%	6,074.3	13.9%	1.1%
Run of River Hydro	7,000.9	30.5%	7,609.6	31.3%	0.8%
Solar	531.8	16.0%	970.3	17.7%	1.7%
Steam	388,709.8	43.8%	375,485.9	32.5%	(11.3%)
Wind	16,609.7	28.4%	17,696.2	28.0%	(0.3%)
Total	873,954.0	47.6%	895,139.6	41.2%	(6.4%)

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

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 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 December 2016



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 5-27.

Figure 5-10 PJM equivalent outage and availability factors: 2007 to 2016

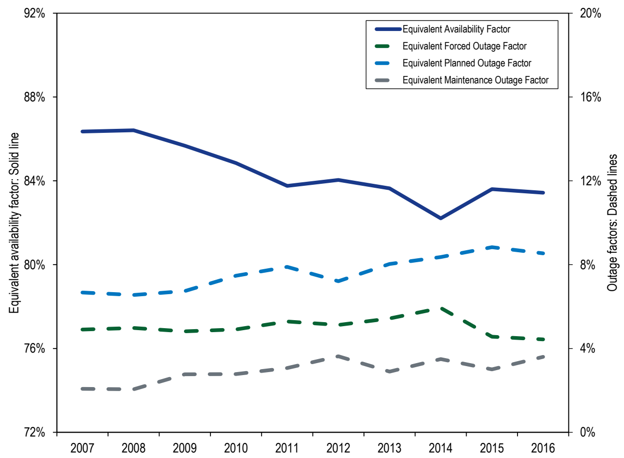


Table 5-27 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2016

	Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Steam			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	2.3%	6.1%	1.8%	89.8%	4.4%	2.4%	2.5%	90.6%	10.2%	0.6%	1.6%	87.6%	1.3%	7.2%	1.4%	90.1%	1.3%	5.3%	0.3%	93.1%	7.3%	8.6%	2.7%	81.4%
2008	2.1%	5.9%	1.7%	90.4%	2.7%	4.0%	2.2%	91.1%	9.1%	1.0%	1.2%	88.7%	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	7.9%	8.0%	2.6%	81.6%
2009	2.7%	6.3%	3.1%	87.9%	1.5%	2.8%	2.3%	93.4%	6.6%	0.6%	1.1%	91.7%	2.3%	8.7%	2.3%	86.8%	4.1%	5.2%	0.6%	90.1%	6.8%	8.5%	3.7%	81.0%
2010	2.6%	8.5%	3.0%	86.0%	1.9%	3.0%	2.0%	93.1%	4.4%	0.4%	1.5%	93.6%	0.7%	8.6%	1.9%	88.8%	2.3%	5.4%	0.5%	91.8%	7.7%	9.3%	3.9%	79.0%
2011	2.4%	9.6%	2.4%	85.5%	2.0%	3.8%	2.4%	91.8%	3.3%	0.1%	1.8%	94.8%	1.7%	11.7%	1.9%	84.7%	2.6%	6.1%	1.2%	90.1%	8.3%	9.2%	4.2%	78.3%
2012	3.6%	8.1%	2.6%	85.7%	2.8%	3.2%	1.7%	92.4%	3.9%	0.7%	2.4%	93.1%	2.8%	6.3%	2.1%	88.8%	1.5%	6.4%	1.1%	91.1%	7.8%	8.7%	5.6%	77.9%
2013	2.4%	8.6%	2.4%	86.5%	5.0%	4.0%	1.9%	89.1%	6.0%	0.3%	1.4%	92.4%	2.3%	7.8%	1.9%	87.9%	1.1%	5.9%	0.7%	92.2%	8.3%	10.2%	4.3%	77.2%
2014	2.6%	10.6%	2.5%	84.4%	6.0%	3.8%	1.9%	88.3%	13.8%	0.4%	2.2%	83.5%	2.5%	9.3%	3.0%	85.2%	1.8%	5.8%	0.9%	91.5%	8.8%	10.3%	5.5%	75.4%
2015	2.1%	10.6%	2.1%	85.2%	2.8%	4.5%	2.5%	90.2%	7.6%	0.3%	2.7%	89.4%	3.7%	9.6%	1.5%	85.2%	1.3%	5.5%	1.2%	91.9%	7.4%	11.3%	4.4%	77.0%
2016	2.6%	10.5%	1.7%	85.1%	2.1%	5.7%	2.7%	89.6%	5.4%	0.2%	2.6%	91.8%	2.4%	7.7%	3.3%	86.6%	1.7%	5.5%	1.2%	91.7%	7.4%	10.4%	5.8%	76.3%

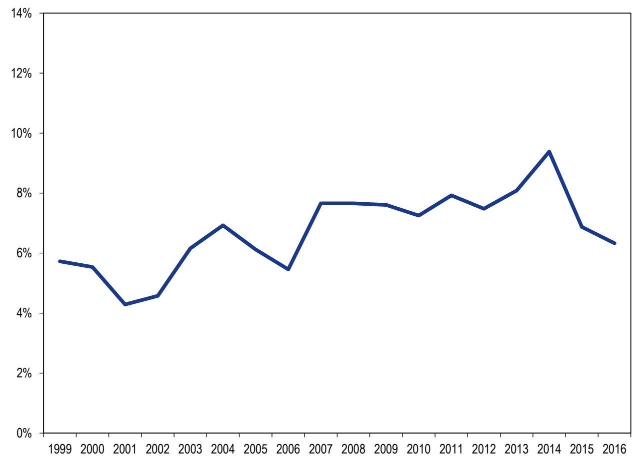
Generator Forced Outage Rates

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.[95] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2016 was 6.3 percent, a decrease from 7.0 percent for 2015. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[96]

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2016



95 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.

96 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2016 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Table 5-28 shows the class average EFORd by unit type.

Table 5-28 PJM EFORd data for different unit types: 2007 through 2016

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Combined Cycle	3.7%	3.7%	4.1%	3.8%	3.4%	4.3%	3.1%	4.3%	2.8%	3.3%
Combustion Turbine	11.0%	11.1%	9.7%	9.0%	8.0%	8.2%	10.7%	15.8%	8.8%	5.8%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.1%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.7%	3.8%	5.2%	3.5%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%
Steam	9.1%	10.1%	9.3%	9.8%	11.2%	10.6%	11.6%	12.1%	10.2%	10.0%
Total	7.0%	7.7%	7.6%	7.3%	7.9%	7.5%	8.1%	9.4%	7.0%	6.3%

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.[97]

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[98] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions," also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[99] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC

97 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.
98 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_K_Outside_Plant_Management_Control.pdf>.
99 For a list of these cause codes, see the *Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per NERC.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metrics used in the capacity market.[100] That choice was made by PJM and can be modified without violating any NERC requirements.[101] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM chose to exclude only some of the OMC outages from the XEFORd metric.

PJM does not have a clear, documented, public set of criteria for designating outages as OMC, although PJM's actual practice appears to be improving.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd.

Table 5-29 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.0 percent of all forced outages in 2016. The largest contributor to OMC outages, flood, was the cause of 37.5 percent of OMC outages and 1.5 percent of all forced outages.

100 For example, the NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules. See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf>. When a generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of unforced capacity such installed capacity suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as outside management control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

101 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

Table 5-29 OMC outages: 2016

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Flood	37.5%	1.5%
Lack of fuel	17.8%	0.7%
Transmission line	11.9%	0.5%
Transmission system problems other than catastrophes	11.5%	0.5%
Other switchyard equipment	8.0%	0.3%
Transmission equipment beyond the 1st substation	6.1%	0.2%
Lack of water (hydro)	2.8%	0.1%
Switchyard circuit breakers	1.5%	0.1%
Lightning	1.0%	0.0%
Other miscellaneous external problems	0.6%	0.0%
Transmission equipment	0.6%	0.0%
Wet coal	0.5%	0.0%
Other catastrophe	0.1%	0.0%
Switchyard system protection devices	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Other fuel quality problems	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Storms	0.0%	0.0%
Fire	0.0%	0.0%
Total	100.0%	4.0%

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.[102]

Lack of fuel is an example of why, even if the OMC concept were accepted, many types of OMC outages are not actually outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts, including contracts with intermediaries, could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could

102 For more on this issue, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage.

If a particular unit or set of units have outages for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.

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 after appropriate notice. OMC outages should not be reflected in forced outage metrics which affect market payments to generating units. OMC outages will be eliminated under the capacity performance rules.

Performance Incentives

There are a number of performance incentives in the current (pre capacity performance) 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 market design is implemented beginning with 2018/2019 Delivery Year, but remain essential reasons why the incentive components of capacity performance design are necessary.

The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. Under the current RPM design, in place in 2016, in addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives were not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

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

In concept, units do not receive RPM revenues to the extent that they do not perform during defined peak hours, but there are significant limitations on this incentive in the current rules.

The maximum level of RPM revenues at risk are based on the difference between a unit's actual Peak Period Capacity Available (PCAP) and the unit's expected Target Unforced Capacity (TCAP). PCAP is based on EFORp while TCAP is based on XEFORd- 5. PCAP is the resource position, while TCAP is the resource commitment. In other words, if the forced outage rate during the peak hours (EFORp) is greater than the forced outage rate calculated over a five year period (XEFORd-5), the unit owner may have a capacity shortfall of up to 50 percent of the unit's capacity commitment in the first year.

(PCAP) Peak Period Capacity = ICAP * (1 - EFORp)

(TCAP) Target Unforced Capacity = ICAP *
(1 – XEFORd-5)

Peak Period Capacity Shortfall = TCAP – PCAP

The peak-hour period availability charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[103]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final effective EFORd, which is defined

103 PJM. OATT Attachment DD § 10 (j).

to be the XEFORd calculated for the 12 months ending in September in the year prior to the delivery year.[104]

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[105]

Excess available capacity (EAC) may also be used to offset peak hour availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[106]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the peak-hour period availability charge during the winter if the capacity shortfall was due to nonavailability of gas to supply the unit.[107] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[108]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[109]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[110]

104 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 4.2.5
105 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.
106 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.1.
107 PJM. OATT Attachment DD § 7.10 (e).
108 *Id.*
109 *Id.*
110 *Id.*

Under the peak hour availability charge, the maximum exposure to loss of capacity market revenues is 50 percent in the first year of higher than 50 percent EFORp. That percent increases to 75 percent in year two of sub 50 percent performance and to 100 percent in year three, but returns to a maximum of 50 percent after three years of better performance.

This limitation on maximum exposure is in addition to limitations that result from the way in which PJM applies the OMC rules in the calculation of EFORp and XEFORd, is in addition to the exclusion for gas availability in the winter, which is over and above the OMC exclusion, and is in addition to the case where a unit has less than 50 service hours in a delivery year and can use the lower of the delivery year XEFORd or EFORp.

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[111]

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.[112] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[113]

PJM EFOF was 4.4 percent in 2016. This means there was 4.4 percent lost availability because of forced outages. Table 5-30 shows that forced outages for boiler tube leaks, at 21.2 percent of the systemwide EFOF, were the largest single contributor to EFOF.

111 PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015).
112 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.
113 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-30 Contribution to EFOF by unit type by cause: 2016

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.2%	0.0%	0.0%	0.0%	0.0%	29.1%	21.2%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	10.2%	7.4%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	9.0%	6.5%
Miscellaneous (Generator)	1.9%	8.0%	8.6%	10.2%	0.8%	4.3%	4.3%
Feedwater System	2.4%	0.0%	0.0%	0.0%	1.2%	5.3%	4.2%
Electrical	8.1%	7.8%	3.7%	19.5%	1.6%	2.9%	4.1%
Reserve Shutdown	1.4%	13.4%	15.7%	21.1%	4.1%	2.8%	4.1%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	4.2%	3.1%
Miscellaneous (Balance of Plant)	6.1%	1.8%	0.0%	4.3%	1.0%	2.9%	3.0%
Controls	2.9%	0.4%	2.0%	0.8%	25.7%	0.9%	2.9%
Generator	3.2%	0.5%	12.4%	4.3%	0.0%	3.1%	2.7%
Economic	1.0%	20.8%	5.5%	9.3%	0.0%	1.0%	2.7%
Boiler Piping System	3.6%	0.0%	0.0%	0.0%	0.0%	2.3%	2.0%
Condensing System	0.5%	0.0%	0.0%	0.0%	1.6%	2.0%	1.7%
Reactor Vessel and Internals	0.0%	0.0%	0.0%	0.0%	22.1%	0.0%	1.6%
Circulating Water Systems	1.4%	0.0%	0.0%	0.0%	0.6%	2.0%	1.6%
Miscellaneous (Steam Turbine)	7.9%	0.0%	0.0%	0.0%	4.1%	0.7%	1.6%
Miscellaneous (Gas Turbine)	7.5%	10.6%	0.0%	0.0%	0.0%	0.0%	1.6%
Catastrophe	15.4%	0.4%	0.1%	1.1%	0.0%	0.0%	1.6%
All Other Causes	34.1%	36.5%	52.0%	29.4%	36.9%	17.2%	22.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-31 shows the categories which are included in the economic category.[114] Lack of fuel that is considered outside management control accounted for 26.3 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."[115] 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 5-31 Contributions to Economic Outages: 2016

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	62.7%
Lack of fuel (OMC)	26.3%
Other economic problems	5.4%
Lack of water (hydro)	4.2%
Fuel conservation	1.2%
Wet fuel (biomass)	0.2%
Ground water or other water supply problems	0.1%
Problems with primary fuel for units with secondary fuel operation	0.0%
Total	100.0%

114 The definitions of these outages are defined by NERC GADS.
115 The definitions of these outages are defined by NERC GADS.

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.

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.[116] 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.

116 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

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 5-32 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

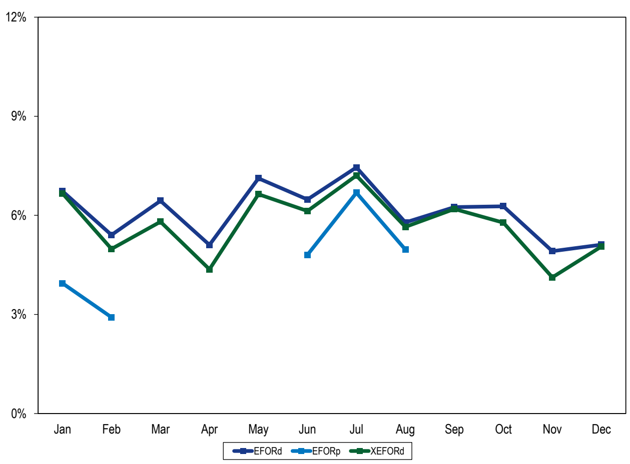
Table 5-32 PJM EFORd, XEFORd and EFORp data by unit type: 2016[117]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.3%	2.6%	1.5%	0.7%	1.8%
Combustion Turbine	5.8%	5.3%	3.3%	0.4%	2.5%
Diesel	7.1%	6.4%	4.1%	0.8%	3.0%
Hydroelectric	3.5%	3.1%	2.3%	0.4%	1.2%
Nuclear	1.9%	1.8%	3.3%	0.1%	(1.4%)
Steam	10.0%	9.8%	8.1%	0.2%	1.9%
Total	6.3%	6.0%	5.0%	0.3%	1.3%

Performance by Month

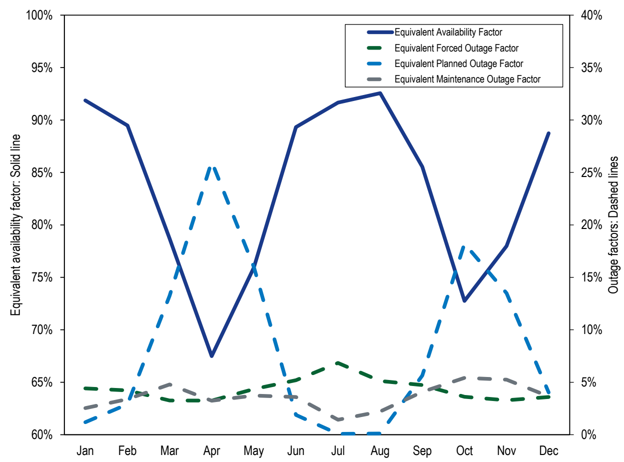
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 PJM EFORd, XEFORd and EFORp: 2016



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: 2016



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