

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 the first three months of 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

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.

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

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.

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 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 2016/2017 RPM Third Incremental Auction was conducted in the first three months 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 Delivery Years 2016/2017 and 2017/2018. 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 purposes 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

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

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 32 (April 1, 2016), p. 7.

Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.¹⁰

RPM prices are locational and may vary depending on transmission constraints.¹¹ 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 the first three months of 2016, PJM installed capacity increased 809.2 MW or 0.5 percent, from 177,682.8 MW on January 1 to 178,492.0 MW on March 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 March 31, 2016, 37.4 percent was coal; 34.3 percent was gas; 18.6 percent was nuclear; 3.8 percent was oil; 5.0 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.

¹⁰ The MMU will publish a detailed report on the operation and design of the transition auctions in 2016.

¹¹ 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.

- **Market Concentration.** In the 2016/2017 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.¹² 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.^{13 14 15}
- **Imports and Exports.** Of the 599.7 MW of imports in the 2016/2017 RPM Third Incremental Auction, 8.0 MW cleared. Of the cleared imports, 4.9 MW (61.3 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,493.8 MW).

Market Conduct

- **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).

¹² 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).

¹³ See PJM. OATT Attachment DD § 6.5.

¹⁴ 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.

¹⁵ 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).

Market Performance

- The 2016/2017 RPM Third Incremental Auction was conducted in the first three months of 2016. The weighted average capacity price for the 2016/2017 Delivery Year is \$121.85 per MW-day, including all RPM Auctions for the 2016/2017 Delivery Year. The weighted average capacity price for the 2017/2018 Delivery Year is \$142.83, including all RPM Auctions for the 2017/2018 Delivery Year held through the first three months of 2016. The weighted average capacity price for the 2018/2019 Delivery Year is \$179.60, including all RPM Auctions for the 2018/2019 Delivery Year held through the first three months of 2016.
- For the 2015/2016 Delivery Year, RPM annual charges to load are \$9.6 billion. 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.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORD for the first three months of 2016 was 6.0 percent, a decrease from 9.4 percent for the first three months of 2015.¹⁶
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first three months of 2016 was 86.4 percent, a slight increase from 86.3 percent for the first three months of 2015.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2016, 4.0 percent of forced outages were classified as OMC outages, an increase from 3.2 percent in 2015.

¹⁶ 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 April 26, 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.

Recommendations¹⁷

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.¹⁸

- 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.^{19 20} (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas 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 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 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.^{21 22} 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 of modeling assumptions.²³ (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.)

¹⁷ 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.

¹⁸ *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

¹⁹ See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

²⁰ See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

²¹ See *PJM Interconnection, L.L.C.*, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

²² See the 2012 *State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

²³ See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU 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 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.)
- 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.)
- The MMU recommends four changes with respect to capacity imports into PJM:
 - The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)
 - 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. New recommendation. Status: Not Adopted.)
 - 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.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
 - 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.)
 - 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 2013. Status: Not adopted. Pending before FERC.)
 - 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.²⁴ (Priority: Medium. First reported 2013. Status: Adopted 2015.)
- 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.)

²⁴ 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).

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_for_Leave_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_EL15-29-000_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_ER15-70-000_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 AEMA 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
February 24, 2016	IMM Comments re DR CBL Testing http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Comments_Docket_No_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

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 the first three months of 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 the first three months of 2016.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.^{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 first Capacity Performance BRA for 2018/2019 and on the CP Transition Incremental Auctions which include more specific issues and suggestions for improvements.

25 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

26 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

27 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

28 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).

29 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).

Installed Capacity

On January 1, 2016, PJM installed capacity was 177,682.8 MW (Table 5-3).³⁰ Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 178,492.0 MW on March 31, 2016, an increase of 809.2 MW or 0.5 percent from the January 1 level.^{31 32} The 809.2 MW increase was the result of capacity modifications (105.0 MW) and new or reactivated generation (994.8 MW), offset by deactivations (51.0 MW), derates (54.6 MW), and a decrease in imports (185.0 MW).

At the beginning of the new Delivery Year on June 1, 2015, PJM installed capacity was 176,737.4 MW, a decrease of 6,239.4 MW or 3.4 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, 2015, as well as the expected installed capacity for the next three Delivery Years, based on the results of all auctions held through March 31, 2016.³³ On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 37.8 percent on June 1, 2015 and will decrease to 31.4 percent by June 1, 2018. The share of gas increased from 29.1 percent in 2007 to 33.6 percent in 2015, and will increase to 42.2 percent in 2018.

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

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

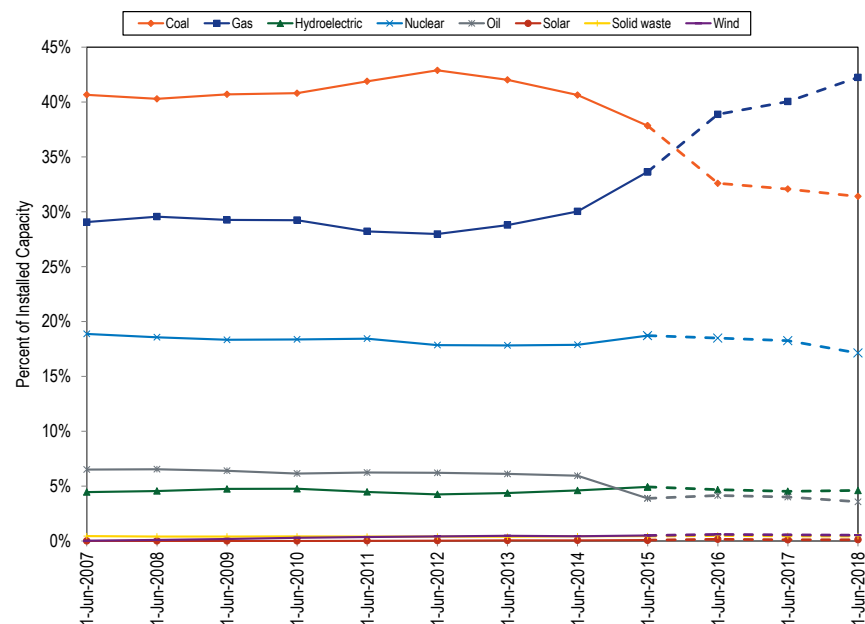
32 Wind resources accounted for 918.4 MW of installed capacity in PJM on March 31, 2016. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

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

Table 5-3 PJM installed capacity (By fuel source): January 1, January 31, February 29, and March 31, 2016

	1-Jan-16		31-Jan-16		29-Feb-16		31-Mar-16	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,674.8	37.5%	66,674.8	37.3%	66,672.7	37.4%	66,672.7	37.4%
Gas	60,487.4	34.0%	61,180.9	34.3%	61,144.8	34.3%	61,187.9	34.3%
Hydroelectric	8,787.5	4.9%	8,846.4	5.0%	8,846.4	5.0%	8,854.8	5.0%
Nuclear	33,071.5	18.6%	33,175.5	18.6%	33,175.5	18.6%	33,175.5	18.6%
Oil	6,851.8	3.9%	6,851.8	3.8%	6,787.2	3.8%	6,787.2	3.8%
Solar	128.0	0.1%	128.0	0.1%	128.0	0.1%	128.0	0.1%
Solid waste	769.4	0.4%	769.4	0.4%	767.5	0.4%	767.5	0.4%
Wind	912.4	0.5%	918.4	0.5%	918.4	0.5%	918.4	0.5%
Total	177,682.8	100.0%	178,545.2	100.0%	178,440.5	100.0%	178,492.0	100.0%

Figure 5-1 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2018



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.³⁴ In the first three months of 2016, the 2016/2017 RPM Third Incremental Auction was conducted.

³⁴ See *PJM Interconnection, LLC*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Table 5-4 Generation capacity changes: 2007/2008 through 2015/2016

	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	2,229.2	21.6	4,027.7	420.0	(1,556.6)
2014/2015	184,011.3	3,036.0	0.0	480.4	0.0	946.9	73.3	11,442.9	221.0	(7,273.9)
2015/2016	176,737.4									
Total		9,787.1	430.0	5,101.3	18,109.0	5,310.8	(2,547.0)	25,297.3	2,909.9	13,078.0

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2014/2015 Delivery Year. The 13,078.0 MW increase was the result of new Generation Capacity Resources (9,787.1 MW), reactivated Generation Capacity Resources (430.0 MW), uprates (5,101.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,310.8 MW), a net decrease in capacity exports (2,547.0 MW), offset by deactivations (25,297.3 MW) and derates (2,909.9 MW). In the 2016/2017 RPM Third Incremental Auction, 1,465.3 MW cleared of the 5,164.0 MW of participant sell offers. Effective with the 2012/2013 Delivery Year, PJM sell offers are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements. In the 2016/2017 RPM Third Incremental Auction, 4,818.0 MW cleared of the 5,223.4 MW of PJM sell offers for the RTO.

Demand

In the 2016/2017 RPM Third Incremental Auction, 6,021.3 MW cleared of the 12,240.5 MW of participant buy bids, and 262.0 MW cleared of the 262.0 MW of PJM buy bids for the RTO. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to

purchase additional capacity. PJM buy bids are submitted due to reliability requirement adjustments and, for RPM Auction for Delivery Years prior to 2018/2019, deferred short term resource procurement.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The 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, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 65.1 percent (Table 5-5), down from 71.1 percent on June 1, 2014. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 34.9 percent, up from 28.9 percent on June 1, 2014. 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, 2015 is shown in Figure 5-2. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 65.1 percent on June 1, 2015. 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 34.9 percent on June 1, 2015. 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 5-2 Capacity market load obligation served: June 1, 2007 through June 1, 2015

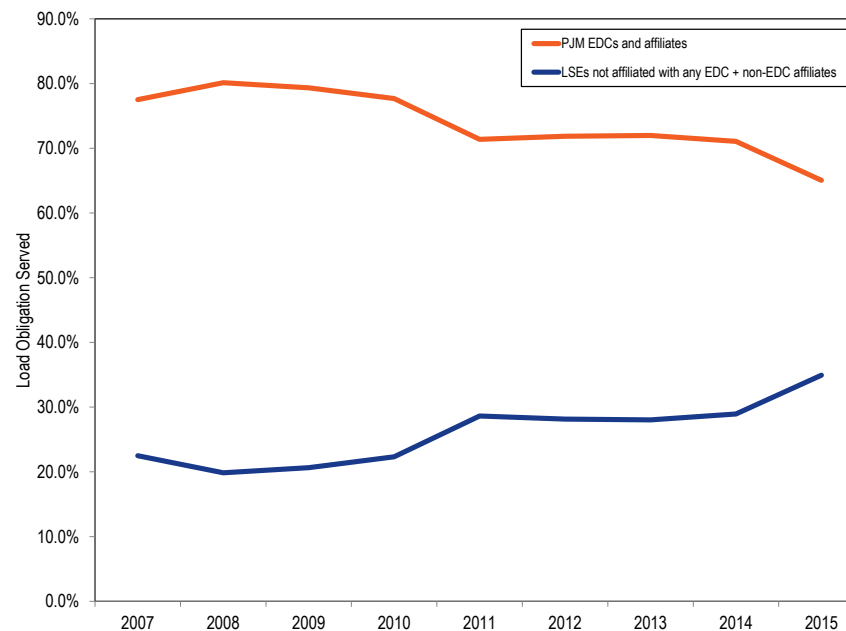


Table 5-5 Capacity market load obligations served: June 1, 2015

	Obligation (MW)								Total
	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		
Obligation	45,896.8	25,878.6	14,327.3	4,630.2	16,352.3	1,265.5	23,994.8		132,345.5
Percent of total obligation	34.7%	19.6%	10.8%	3.5%	12.4%	1.0%	18.1%		100.0%

Market Concentration

Auction Market Structure

As shown in Table 5-6, 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 Third Incremental Auction.³⁵ 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.^{36 37 38}

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 5-6 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.

³⁵ 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.

³⁶ See PJM. OATT Attachment DD § 6.5.

³⁷ 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.

³⁸ 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 5-6 RSI results: 2015/2016 through 2018/2019 RPM Auctions³⁹

RPM Markets	RSI _{1,1.05}	RSI ₃	Total Participants	Failed RSI ₃ Participants
2015/2016 Base Residual Auction				
RTO	0.75	0.57	99	99
MAAC	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC	0.15	0.09	5	5
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2015/2016 Second Incremental Auction				
RTO	0.40	0.21	26	26
MAAC	0.00	0.04	4	4
PSEG	0.00	0.00	0	0
ATSI	0.00	0.00	1	1
2015/2016 Third Incremental Auction				
RTO	0.38	0.28	55	55
MAAC	0.24	0.10	4	4
PSEG	0.00	0.00	0	0
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
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

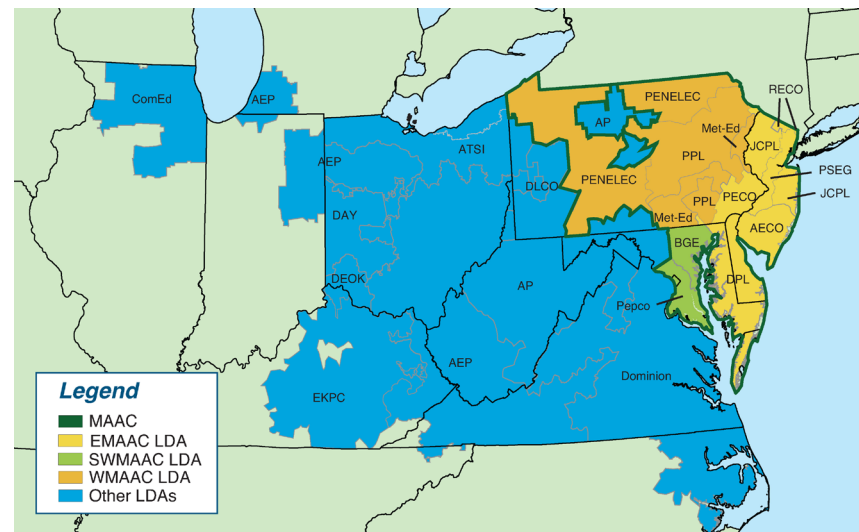
³⁹ The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a Delivery Year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.⁴⁰ 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.”⁴¹ 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.⁴² 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 5-3, Figure 5-4 and Figure 5-5.

Figure 5-3 Map of PJM Locational Deliverability Areas



40 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.

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

42 146 FERC ¶ 61,052 (2014).

Figure 5-4 Map of PJM RPM EMAAC subzonal LDAs

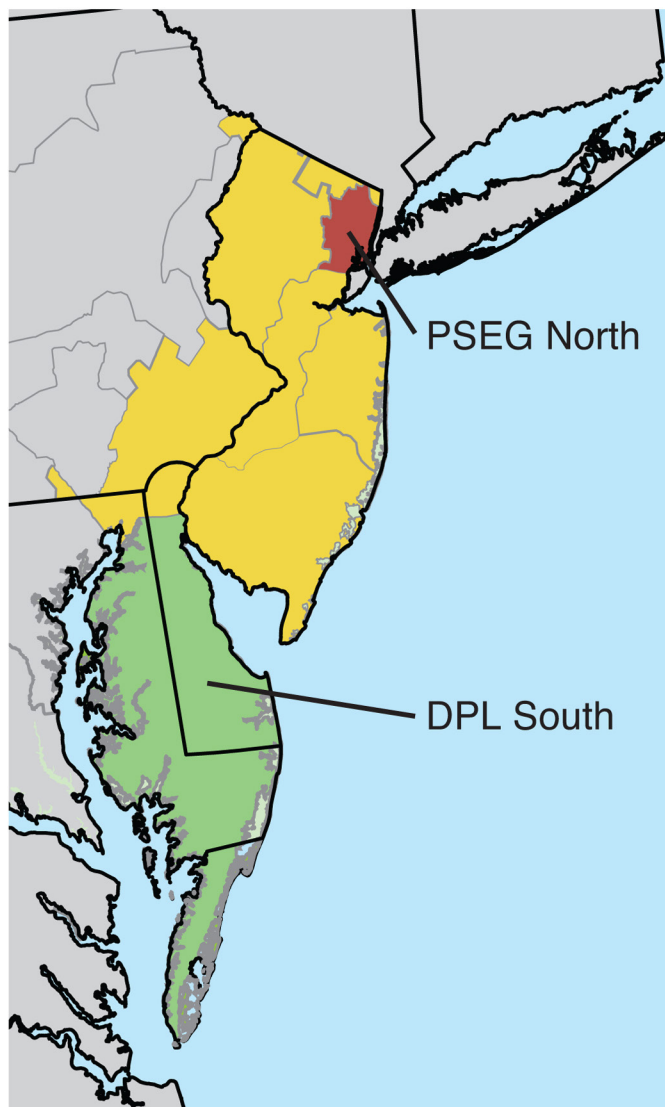
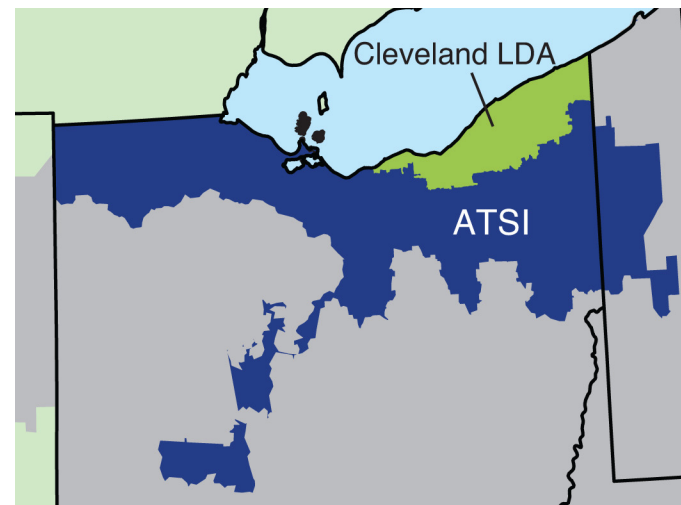


Figure 5-5 Map of PJM RPM ATSI subzonal LDA



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.⁴³

Of the 599.7 MW of imports in the 2016/2017 RPM Third Incremental Auction, 8.0 MW cleared. Of the cleared imports, 4.9 MW (61.3 percent) were from MISO.

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

⁴³ PJM. OATT Attachment DD § 5.6.6(b).

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

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.⁴⁴ 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.⁴⁵

⁴⁴ 147 FERC ¶ 61,060 (2014).

⁴⁵ 151 FERC ¶ 61,208 (2015).

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.^{46 47} 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 non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.⁴⁸

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

⁴⁶ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

⁴⁷ See PJM, "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 51-52 & pp. 74-75.

⁴⁸ OATT, Schedule 1, Section 1.10.1A.

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.^{49 50} Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.⁵¹ 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.⁵²

Exporting Capacity

Non-firm 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.⁵³ The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.⁵⁴

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.⁵⁵

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 5-7 RPM imports: 2007/2008 through 2018/2019 RPM Base Residual Auctions

Base Residual Auction	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
	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

⁴⁹ See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Section 1.69A.

⁵⁰ See PJM, "Manual 18: PJM Capacity Market," Revision 32 (April 1, 2016), pp. 53-54.

⁵¹ 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).

⁵² 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).

⁵³ OATT Attachment DD § 6.6(g).

⁵⁴ *Id.*

⁵⁵ OATT Attachment M-Appendix § ILC.2.

Demand Resources

There are three basic demand products incorporated in the RPM market design:⁵⁶

- **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.⁵⁷

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:^{58 59}

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

- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for only ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of Demand Resource and Energy Efficiency Resource products included in the RPM market design:^{60 61}

- **Base Capacity Demand Resource.** Demand Resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base Capacity DR is required to be capable of maintaining each interruption for at least ten hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Base Capacity Energy Efficiency Resource.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the Base Capacity Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Base Capacity Energy Efficiency Resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

⁵⁶ 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.

⁵⁷ Letter Order in Docket No. ER10-366-000 (January 22, 2010).

⁵⁸ 134 FERC ¶ 61,066 (2011).

⁵⁹ "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

⁶⁰ 151 FERC ¶ 61,208.

⁶¹ "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

- Capacity Performance Resource
 - **Annual Demand Resource.** 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.

Table 5-8 RPM load management statistics by LDA: June 1, 2014 to June 1, 2018^{62 63 64}

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
DR cleared	14,943.0	7,452.4	2,976.9	2,268.4	220.9	999.5	468.4	920.0					
EE cleared	1,077.7	305.9	45.2	169.8	8.1	24.2	11.9	51.4					
DR net replacements	(6,731.8)	(3,778.7)	(1,651.1)	(1,010.7)	(156.0)	(550.4)	(231.1)	(428.9)					
EE net replacements	204.7	219.5	46.8	148.2	(6.8)	12.7	5.0	68.3					
RPM load management @ 01-Jun-14	9,493.6	4,199.1	1,417.8	1,575.7	66.2	486.0	254.2	610.8					
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				
EE cleared	1,189.6	279.0	73.1	164.8	3.1	26.4	11.5	59.3	142.0				
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)				
EE net replacements	335.9	230.4	48.5	149.2	0.0	12.4	2.7	61.1	15.2				
RPM load management @ 01-Jun-15	12,149.5	4,791.8	1,666.9	1,663.9	79.0	462.5	149.3	677.4	1,242.9				
DR cleared	13,277.1	5,409.8	2,029.3	1,622.6	105.7	634.4	230.3	683.9	1,841.4	470.8			
EE cleared	1,723.2	418.0	86.4	262.6	2.0	27.9	10.8	136.5	226.9	58.6			
DR net replacements	(2,163.6)	(1,096.3)	(479.2)	(148.6)	(29.4)	(132.6)	(25.5)	(90.3)	(322.6)	(153.0)			
EE net replacements	(92.1)	(4.1)	(1.7)	0.0	0.0	0.0	0.0	0.0	(82.9)	(15.9)			
RPM load management @ 01-Jun-16	12,744.6	4,727.4	1,634.8	1,736.6	78.3	529.7	215.6	730.1	1,662.8	360.5			
DR cleared	11,623.2	4,545.3	1,610.4	1,445.4	86.3	389.6	151.7	639.6	1,049.8	290.3	1,600.8	805.8	811.9
EE cleared	1,611.2	411.9	105.4	234.6	2.0	23.0	6.0	110.0	153.1	35.7	727.7	124.6	41.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-17	13,234.4	4,957.2	1,715.8	1,680.0	88.3	412.6	157.7	749.6	1,202.9	326.0	2,328.5	930.4	853.5
DR cleared	11,084.4	4,286.0	1,674.6	1,183.1	86.8	382.2	132.6	523.1	877.0	267.6	1,876.7	660.0	716.2
EE cleared	1,246.5	258.6	54.3	162.3	0.0	14.1	1.8	66.4	38.8	5.6	744.4	95.9	25.0
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-18	12,330.9	4,544.6	1,728.9	1,345.4	86.8	396.3	134.4	589.5	915.8	273.2	2,621.1	755.9	741.2

⁶² 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.

⁶³ 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.

⁶⁴ 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.

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

As shown in Table 5-8 and Table 5-10, capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity (4,493.8 MW). Table 5-9 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 5-9 RPM load management cleared capacity and ILR: 2007/2008 through 2018/2019^{65 66 67}

Delivery Year	DR Cleared		EE Cleared		ILR	
	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	12,748.8	13,277.1	1,656.9	1,723.2	0.0	0.0
2017/2018	11,202.1	11,623.2	1,554.4	1,611.2	0.0	0.0
2018/2019	10,229.3	11,084.4	1,150.5	1,246.5	0.0	0.0

65 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.

66 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.

67 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.

Table 5-10 RPM load management statistics: June 1, 2007 to June 1, 2018^{68 69}

	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	14,405.7	15,000.3	(2,077.3)	(2,163.6)	(88.4)	(92.1)	12,240.0	12,744.6
01-Jun-17	12,756.5	13,234.4	0.0	0.0	0.0	0.0	12,756.5	13,234.4
01-Jun-18	11,379.8	12,330.9	0.0	0.0	0.0	0.0	11,379.8	12,330.9

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.^{70 71 72}

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.⁷³ In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could

68 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.

69 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.

70 See OATT Attachment DD § 6.5.

71 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.

72 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).

73 OATT Attachment DD § 6.8 (b).

be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost-based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.⁷⁴

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

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.⁷⁵ 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.⁷⁶

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.⁷⁷ 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.

2016/2017 RPM Third Incremental Auction

As shown in Table 5-11, 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.

74 OATT Attachment DD § 6.8 (a).

75 135 FERC ¶ 61,022 (2011).

76 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).

77 143 FERC ¶ 61,090 (2013).

Table 5-11 ACR statistics: 2016/2017 RPM Auctions

Offer Cap/Mitigation Type	2016/2017 Base Residual Auction		2016/2017 First Incremental Auction		2016/2017 Second Incremental Auction		2016/2017 Third Incremental Auction	
	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%

Market Performance

Figure 5-6 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-12 shows RPM clearing prices for all RPM Auctions held through the first three months of 2016.

Figure 5-7 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 the first three months of 2016. A summary of these weighted average prices is given in Table 5-13.

Table 5-14 shows RPM revenue by resource type for all RPM Auctions held through the first three months of 2016 with \$5.0 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 5-15 shows RPM revenue by calendar year for all RPM Auctions held through the first three months of 2016. In 2015, RPM revenue was \$9.0 billion. In 2016, RPM revenue will be \$8.9 billion.

Table 5-16 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 5-12 Capacity prices: 2007/2008 through 2018/2019 RPM Auctions

Product Type	RPM Clearing Price (\$ per MW-day)											
	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
2015/2016 BRA	Limited	\$118.54	\$150.00	\$118.54	\$150.00	\$150.00	\$150.00	\$150.00	\$150.00	\$150.00	\$304.62	\$118.54
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
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
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
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
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
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
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
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
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
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
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
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

Table 5-12 Capacity prices: 2007/2008 through 2018/2019 RPM Auctions (continued)

	Product Type	RPM Clearing Price (\$ per MW-day)											
		RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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

Table 5-13 Weighted average clearing prices by zone: 2015/2016 through 2018/2019

LDA	Weighted Average Clearing Price (\$ per MW-day)			
	2015/2016	2016/2017	2017/2018	2018/2019
RTO				
AEP	\$134.00	\$115.27	\$142.03	\$162.73
AP	\$134.00	\$115.27	\$142.03	\$162.73
ATSI	\$327.79	\$122.15	\$140.83	\$162.28
Cleveland	\$327.79	\$112.13	\$140.08	\$163.10
ComEd	\$134.00	\$115.27	\$141.06	\$213.25
DAY	\$134.00	\$115.27	\$142.03	\$162.73
DEOK	\$134.00	\$115.27	\$142.03	\$162.73
DLCO	\$134.00	\$115.27	\$142.03	\$162.73
Dominion	\$134.00	\$115.27	\$142.03	\$162.73
EKPC	\$134.00	\$115.27	\$142.03	\$162.73
MAAC				
EMAAC				
AECO	\$166.51	\$123.01	\$138.50	\$221.00
DPL	\$166.51	\$123.01	\$138.50	\$221.00
DPL South	\$166.80	\$119.87	\$136.25	\$221.72
JCPL	\$166.51	\$123.01	\$138.50	\$221.00
PECO	\$166.51	\$123.01	\$138.50	\$221.00
PSEG	\$166.01	\$220.69	\$209.69	\$223.20
PSEG North	\$163.94	\$218.25	\$214.68	\$224.67
RECO	\$166.51	\$123.01	\$138.50	\$221.00
SWMAAC				
BGE	\$159.24	\$120.96	\$131.02	\$143.54
Pepco	\$166.03	\$118.60	\$135.86	\$153.20
WMAAC				
Met-Ed	\$164.83	\$122.13	\$140.70	\$163.12
PENELEC	\$164.83	\$122.13	\$140.70	\$163.12
PPL	\$164.83	\$122.13	\$136.50	\$154.01

Table 5-14 RPM revenue by type: 2007/2008 through 2018/2019^{78 79}

	Demand Resources	Energy Efficiency Resources	Coal		Gas		Hydroelectric		Nuclear		Oil		Solar		Solid waste		Wind		Total revenue	
			Imports	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated	Existing	New/repower/reactivated			
2007/2008	\$5,537,085	\$0	\$22,225,980	\$1,019,060,206	\$0	\$1,624,111,360	\$3,472,667	\$209,490,444	\$0	\$996,085,233	\$0	\$340,362,114	\$0	\$0	\$31,512,230	\$0	\$430,065	\$0	\$4,252,287,381	
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	\$1,322,601,837	\$0	\$378,756,365	\$4,837,523	\$0	\$0	\$35,011,991	\$0	\$1,180,153	\$2,917,048	\$6,087,147,586
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	\$1,517,723,628	\$0	\$450,523,876	\$5,676,582	\$0	\$0	\$42,758,762	\$523,739	\$2,011,156	\$6,836,827	\$7,503,218,157
2010/2011	\$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	\$1,799,258,125	\$0	\$446,000,462	\$4,339,539	\$0	\$0	\$40,731,606	\$413,503	\$1,819,413	\$15,232,177	\$8,449,652,496
2011/2012	\$55,795,785	\$139,812	\$185,421,273	\$1,586,775,249	\$28,330,047	\$1,717,850,463	\$98,448,693	\$278,529,660	\$0	\$1,079,386,338	\$0	\$266,483,502	\$967,887	\$0	\$66,978	\$25,636,836	\$261,690	\$1,072,929	\$9,919,881	\$5,335,087,023
2012/2013	\$264,387,897	\$11,408,552	\$13,260,822	\$1,014,858,378	\$7,568,127	\$1,256,096,304	\$76,633,409	\$179,117,975	\$11,397	\$762,719,550	\$0	\$248,611,128	\$2,772,987	\$0	\$1,246,337	\$26,840,670	\$316,420	\$812,644	\$5,052,036	\$3,871,714,635
2013/2014	\$558,715,114	\$21,598,174	\$31,804,645	\$1,741,613,525	\$12,950,135	\$2,153,560,721	\$167,844,235	\$308,853,673	\$25,708	\$1,346,223,419	\$0	\$386,561,718	\$5,670,399	\$0	\$3,523,555	\$43,943,130	\$1,977,705	\$1,373,205	\$13,538,988	\$6,799,778,047
2014/2015	\$681,315,139	\$42,308,549	\$135,573,409	\$1,935,468,356	\$57,078,818	\$2,172,570,169	\$205,555,569	\$333,941,614	\$6,649,774	\$1,464,950,862	\$0	\$323,630,668	\$4,106,697	\$0	\$3,836,582	\$34,281,137	\$1,709,533	\$1,524,551	\$32,766,219	\$7,437,267,646
2015/2016	\$903,496,003	\$66,652,986	\$260,806,674	\$2,902,870,267	\$63,682,708	\$2,672,530,801	\$535,039,154	\$389,540,948	\$15,478,144	\$1,850,033,226	\$0	\$401,718,239	\$5,947,275	\$0	\$7,064,983	\$35,862,368	\$6,179,607	\$1,829,269	\$42,994,253	\$10,161,726,902
2016/2017	\$467,895,589	\$68,709,670	\$244,091,507	\$2,137,545,515	\$72,217,195	\$2,212,974,257	\$667,094,476	\$283,613,426	\$13,927,638	\$1,483,759,630	\$0	\$265,547,984	\$4,034,480	\$0	\$7,057,256	\$32,648,789	\$6,380,604	\$1,144,873	\$26,189,042	\$7,994,831,928
2017/2018	\$511,689,437	\$81,758,057	\$214,757,642	\$2,447,236,561	\$62,426,717	\$2,537,120,329	\$979,308,450	\$346,315,522	\$15,183,161	\$1,692,199,258	\$0	\$279,434,857	\$3,888,126	\$0	\$8,393,952	\$34,319,981	\$8,936,300	\$1,298,232	\$39,405,929	\$9,263,672,509
2018/2019	\$634,336,942	\$87,432,139	\$262,415,658	\$2,620,553,513	\$76,339,006	\$2,964,180,164	\$1,434,073,826	\$414,477,423	\$15,344,022	\$1,970,393,801	\$0	\$342,155,243	\$4,047,493	\$0	\$12,998,289	\$37,115,004	\$9,521,591	\$1,164,910	\$52,670,208	\$10,939,219,232

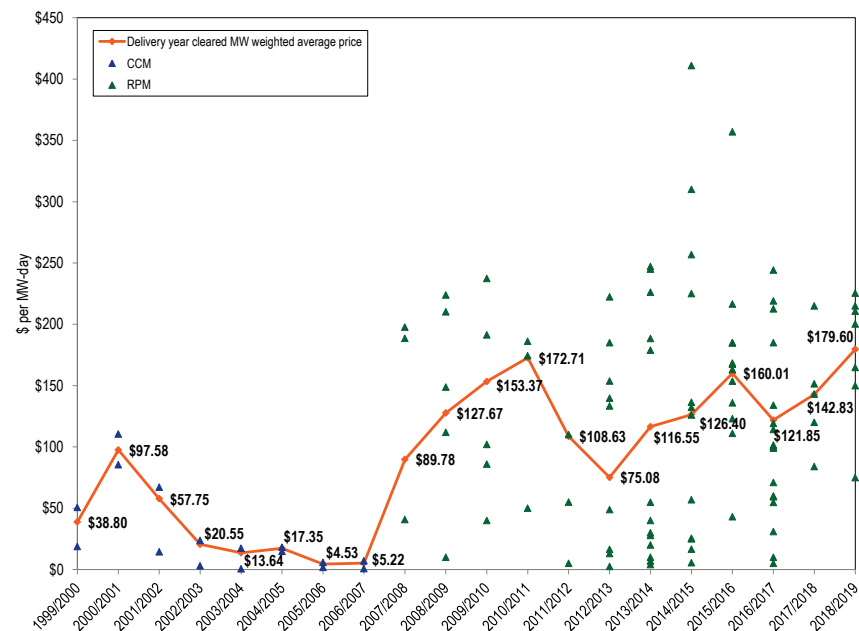
78 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

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

Table 5-15 RPM revenue by calendar year: 2007 through 2019⁸⁰

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	\$137.70	176,748.8	366	\$8,907,551,647
2017	\$134.15	178,468.4	365	\$8,738,754,899
2018	\$164.39	170,763.0	365	\$10,246,047,848
2019	\$179.60	166,875.5	151	\$4,525,540,011

Figure 5-6 History of PJM capacity prices: 1999/2000 through 2018/2019⁸¹



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

81 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2018/2019 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 5-7 Map of RPM capacity prices: 2015/2016 through 2018/2019

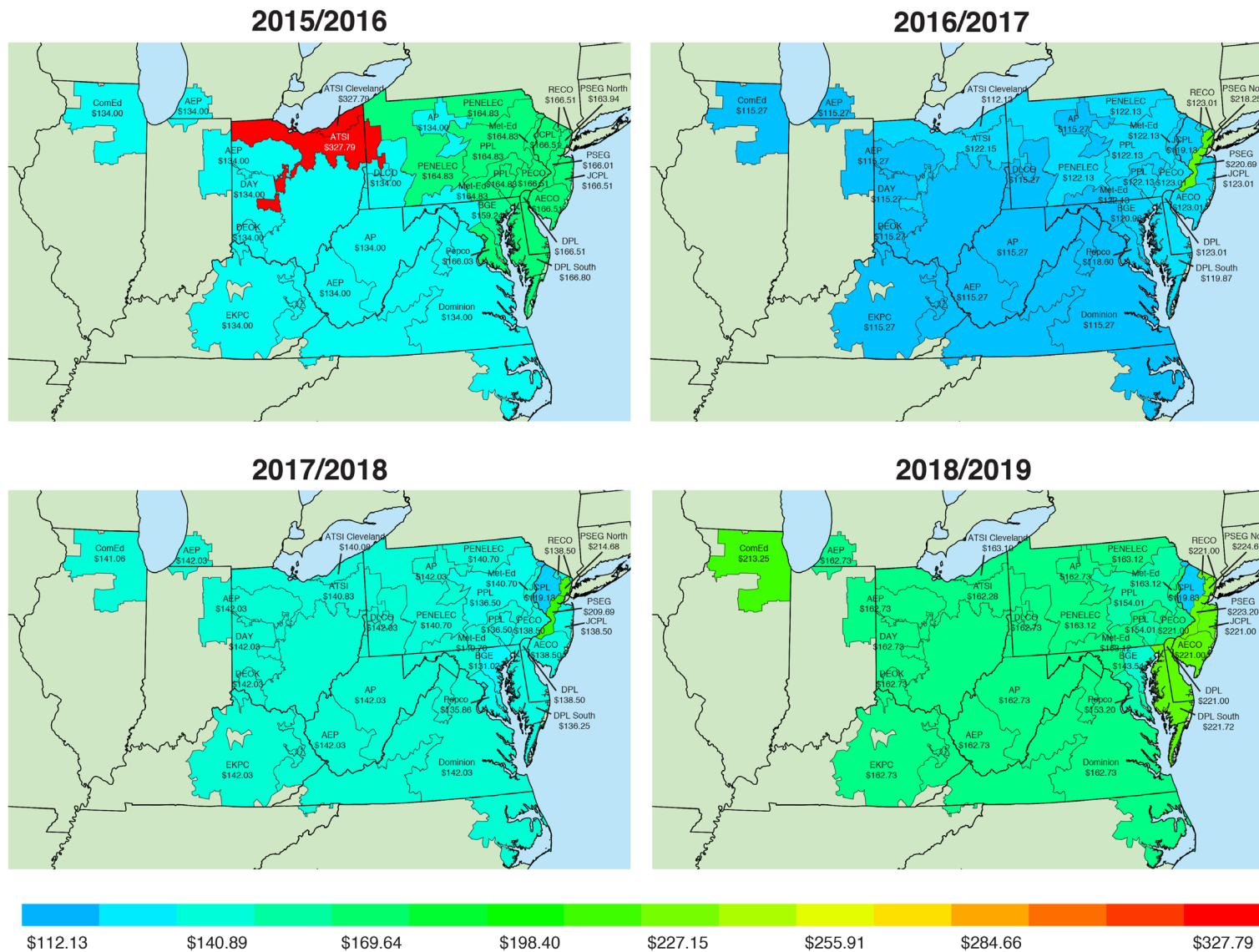


Table 5-16 RPM cost to load: 2015/2016 through 2018/2019 RPM Auctions^{82 83 84}

	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	\$101.55	81,169.7	\$3,008,733,089
Rest of MAAC	\$163.21	52,594.4	\$3,133,152,551
PSEG	\$224.64	11,042.7	\$905,411,924
ATSI	\$133.17	14,084.2	\$684,586,352
Total		158,891.0	\$7,731,883,915
2017/2018			
Rest of RTO	\$149.02	100,253.4	\$5,452,838,631
Rest of MAAC	\$149.13	46,762.9	\$2,545,461,395
PSEG	\$205.78	11,480.6	\$862,291,793
PPL	\$147.33	8,227.7	\$442,440,748
Total		166,724.5	\$9,303,032,568
2018/2019			
Rest of RTO	\$162.44	81,659.7	\$4,841,777,199
Rest of MAAC	\$215.97	36,256.5	\$2,858,052,995
BGE	\$156.03	7,948.5	\$452,674,129
ComEd	\$208.46	25,454.6	\$1,936,809,587
Pepco	\$154.74	7,315.9	\$413,207,985
PPL	\$152.74	8,201.7	\$457,240,705
Total		166,836.9	\$10,959,762,600

⁸² The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

⁸³ 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.

⁸⁴ 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 2016/2017, 2017/2018, and 2018/2019 Net Load Prices are not finalized. The 2016/2017, 2017/2018, and 2018/2019 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 during that period. In the first three months of 2016, nuclear units had a capacity factor of 97.2 percent, compared to 96.3 percent in the first three months of 2015; combined cycle units had a capacity factor of 64.0 percent in the first three months of 2016, compared to a capacity factor of 62.4 percent in the first three months of 2015; and steam units, which are primarily coal fired, had a capacity factor of 41.7 percent in the first three months of 2016, compared to 54.8 percent in the first three months of 2015.

Table 5-17 PJM capacity factor (By unit type (GWh)): January through March, 2015 and 2016⁸⁵

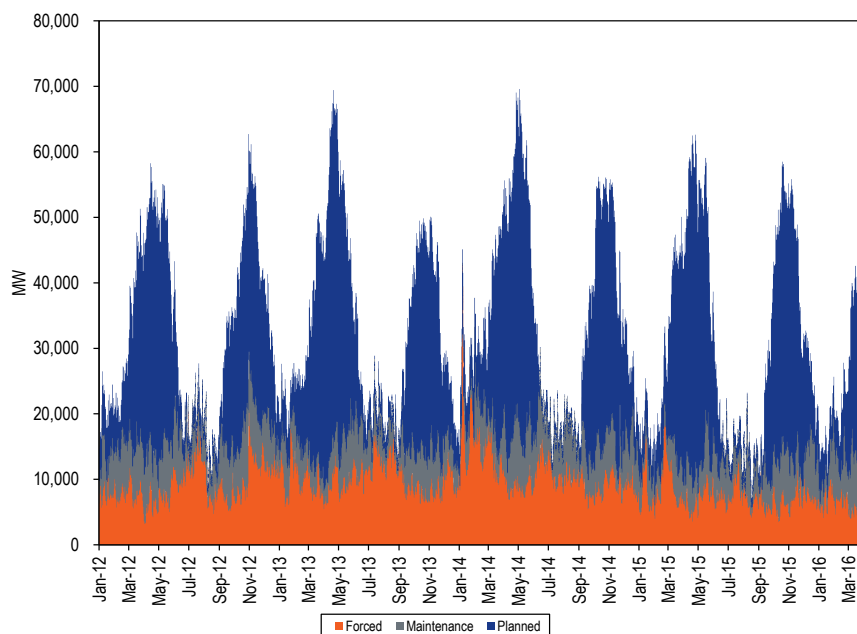
Unit Type	2015 (Jan-Mar)		2016 (Jan-Mar)		Change in 2016 from 2015
	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	
Battery	1.2	0.4%	4.2	0.6%	0.2%
Combined Cycle	37,894.5	62.4%	45,011.7	64.0%	1.6%
Combustion Turbine	2,007.7	3.1%	2,061.3	3.3%	0.2%
Diesel	146.5	15.7%	130.8	13.5%	(2.2%)
Diesel (Landfill gas)	384.6	47.1%	355.5	43.2%	(3.9%)
Fuel Cell	56.4	87.1%	56.2	85.9%	(1.2%)
Nuclear	70,167.1	96.3%	71,578.3	97.2%	0.9%
Pumped Storage Hydro	1,137.0	9.6%	1,199.8	11.0%	1.5%
Run of River Hydro	1,732.5	29.4%	2,956.0	48.8%	19.4%
Solar	93.1	12.1%	174.4	14.4%	2.3%
Steam	94,614.1	54.8%	65,990.2	41.7%	(13.1%)
Wind	4,876.8	34.2%	5,802.6	38.2%	4.0%
Total	213,111.4	52.4%	195,321.1	48.8%	(3.6%)

⁸⁵ 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 varies throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-8, 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 5-8 PJM outages (MW): 2012 through March 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 5-9. Metrics by unit type are shown in Table 5-18 through Table 5-21.

Figure 5-9 PJM equivalent outage and availability factors: January through March, 2007 to 2016

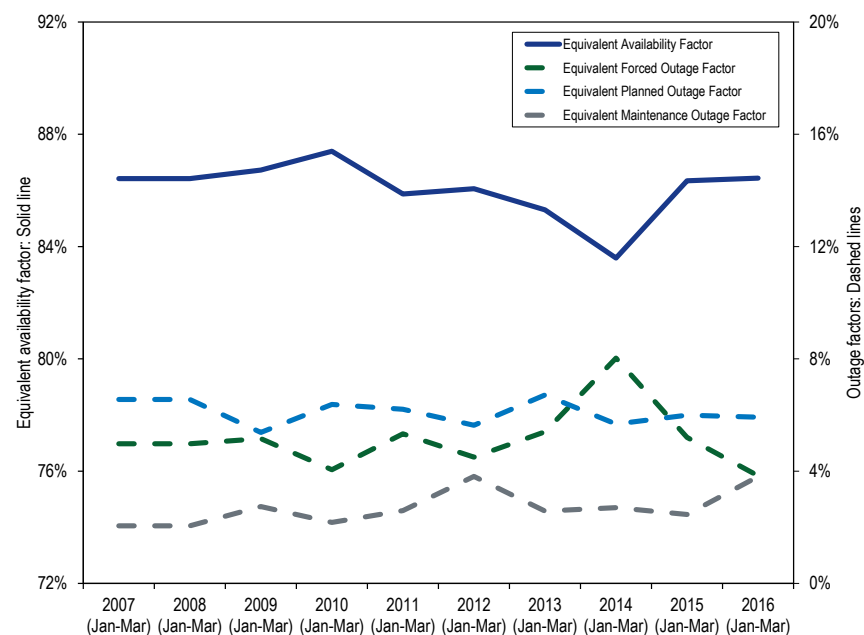


Table 5-18 EAF by unit type: January through March, 2007 through 2016

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)
Combined Cycle	90.4%	90.4%	87.5%	90.4%	86.1%	89.9%	82.8%	84.9%	88.1%	91.9%
Combustion Turbine	91.1%	91.1%	93.5%	94.7%	94.5%	95.0%	91.0%	82.7%	91.1%	93.6%
Diesel	88.7%	88.7%	91.5%	94.5%	93.9%	97.3%	95.1%	82.4%	87.9%	91.2%
Hydroelectric	88.8%	88.8%	87.2%	87.7%	88.0%	92.1%	93.7%	84.1%	87.1%	89.1%
Nuclear	92.3%	92.3%	92.0%	92.3%	93.8%	93.3%	95.6%	92.3%	92.9%	92.9%
Steam	81.6%	81.6%	82.4%	82.5%	79.8%	79.0%	79.4%	80.0%	81.3%	78.6%
Total	86.4%	86.4%	86.7%	87.4%	85.9%	86.1%	85.3%	83.6%	86.3%	86.4%

Table 5-19 EMOF by unit type: January through March, 2007 through 2016

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)
Combined Cycle	1.7%	1.7%	2.8%	2.5%	2.2%	1.8%	2.9%	1.5%	1.6%	1.4%
Combustion Turbine	2.2%	2.2%	1.8%	1.3%	1.6%	1.3%	0.9%	1.1%	1.1%	1.7%
Diesel	1.2%	1.2%	1.7%	0.7%	3.6%	0.8%	1.1%	2.7%	1.9%	2.5%
Hydroelectric	2.1%	2.1%	1.2%	1.5%	0.9%	1.4%	2.3%	5.6%	1.4%	3.6%
Nuclear	0.8%	0.8%	1.0%	0.4%	0.7%	0.5%	0.3%	0.3%	0.5%	1.3%
Steam	2.6%	2.6%	3.8%	3.1%	3.9%	6.5%	4.0%	4.3%	4.1%	6.6%
Total	2.1%	2.1%	2.7%	2.2%	2.6%	3.8%	2.6%	2.7%	2.5%	3.8%

Table 5-20 EPOF by unit type: January through March, 2007 through 2016

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)
Combined Cycle	5.9%	5.9%	6.4%	5.8%	9.0%	6.4%	9.6%	9.7%	7.6%	4.8%
Combustion Turbine	4.0%	4.0%	2.7%	1.8%	2.5%	2.1%	2.7%	2.8%	4.1%	2.6%
Diesel	1.0%	1.0%	0.2%	0.7%	0.0%	0.0%	0.1%	0.0%	0.3%	0.0%
Hydroelectric	7.8%	7.8%	10.0%	10.1%	9.4%	4.8%	3.5%	9.3%	9.7%	5.2%
Nuclear	5.1%	5.1%	3.2%	6.7%	4.0%	5.3%	3.7%	5.8%	5.1%	4.9%
Steam	8.0%	8.0%	6.5%	7.6%	7.3%	6.8%	8.8%	5.3%	6.3%	8.2%
Total	6.6%	6.6%	5.4%	6.4%	6.2%	5.6%	6.7%	5.7%	6.0%	5.9%

Table 5-21 EFOF by unit type: January through March, 2007 through 2016

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)
Combined Cycle	2.1%	2.1%	3.3%	1.3%	2.7%	1.9%	4.7%	3.9%	2.7%	1.9%
Combustion Turbine	2.7%	2.7%	2.0%	2.2%	1.4%	1.6%	5.4%	13.4%	3.7%	2.1%
Diesel	9.1%	9.1%	6.6%	4.1%	2.5%	1.9%	3.7%	14.8%	9.9%	6.3%
Hydroelectric	1.3%	1.3%	1.5%	0.7%	1.7%	1.6%	0.5%	1.1%	1.9%	2.1%
Nuclear	1.8%	1.8%	3.8%	0.7%	1.5%	0.9%	0.5%	1.6%	1.4%	0.9%
Steam	7.9%	7.9%	7.3%	6.8%	9.0%	7.6%	7.9%	10.4%	8.4%	6.7%
Total	5.0%	5.0%	5.2%	4.1%	5.3%	4.5%	5.4%	8.0%	5.2%	3.8%

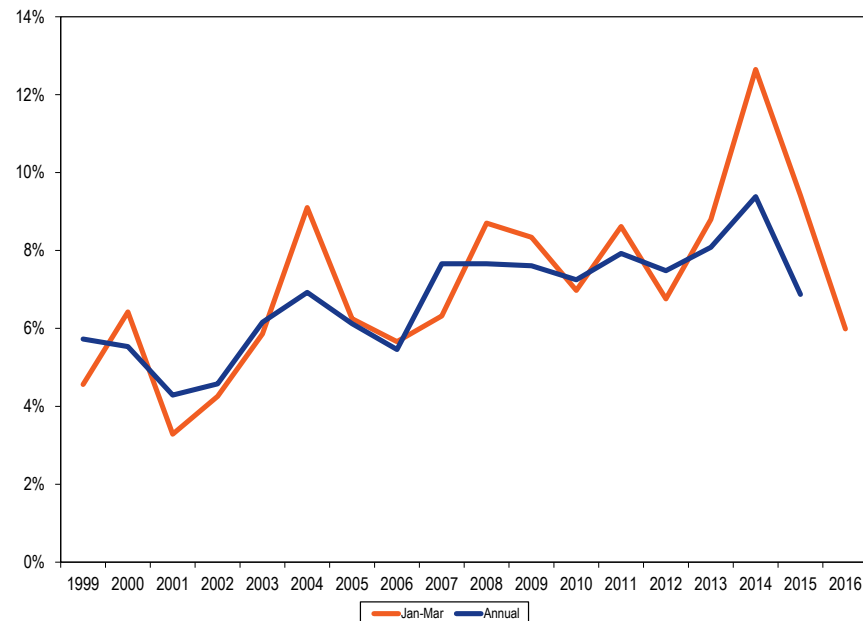
Generator Forced Outage Rates

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

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.⁸⁶ The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first three months of 2016 was 6.0 percent, a decrease from 9.4 percent for the first three months of 2015. Figure 5-10 shows the average EFORd since 1999 for all units in PJM.⁸⁷

Figure 5-10 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2016



⁸⁶ 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.

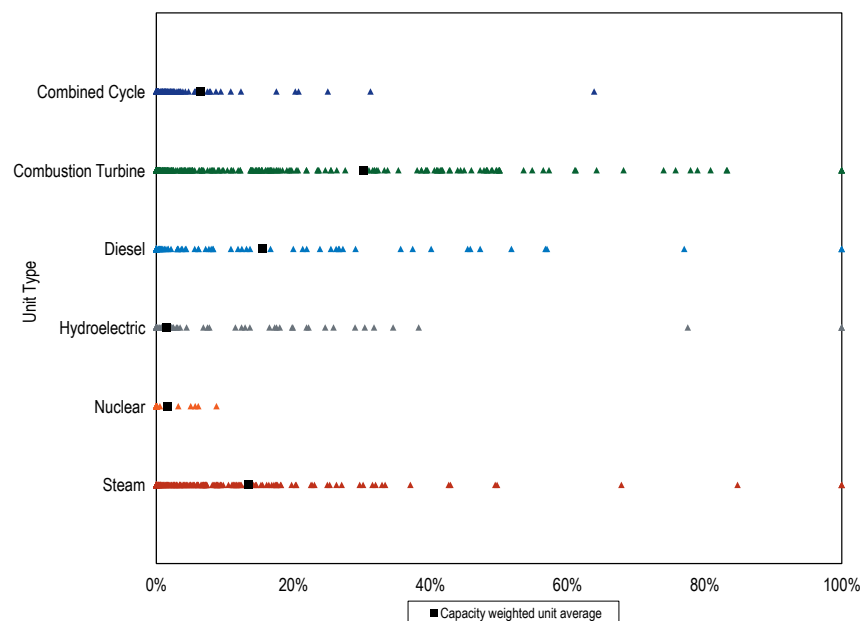
⁸⁷ The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the 2015 State of the Market Report for PJM, Appendix A: "PJM Geography" for details.

Table 5-22 shows the class average EFORD by unit type.

Table 5-22 PJM EFORD data for different unit types: January through March, 2007 through 2016

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	2013 (Jan-Mar)	2014 (Jan-Mar)	2015 (Jan-Mar)	2016 (Jan-Mar)
Combined Cycle	3.7%	3.7%	5.3%	3.5%	3.6%	2.4%	5.3%	6.5%	4.5%	2.6%
Combustion Turbine	11.1%	11.1%	13.9%	13.1%	11.2%	9.3%	19.8%	30.2%	19.7%	8.5%
Diesel	10.3%	10.3%	8.1%	6.2%	5.1%	2.7%	3.8%	15.5%	11.0%	8.0%
Hydroelectric	2.0%	2.0%	2.0%	1.0%	2.2%	2.7%	0.6%	1.5%	2.2%	3.1%
Nuclear	1.9%	1.9%	3.8%	0.7%	1.6%	0.9%	0.5%	1.7%	1.5%	1.0%
Steam	10.1%	10.1%	9.5%	8.6%	12.2%	9.5%	9.9%	13.5%	11.1%	8.8%
Total	7.7%	7.7%	8.3%	7.0%	8.6%	6.8%	8.8%	12.6%	9.4%	6.0%

Figure 5-11 PJM distribution of EFORD data by unit type: January through March, 2016



Distribution of EFORD

The average EFORD results do not show the underlying pattern of EFORD rates within each unit type. The distribution of EFORD by unit type is shown in Figure 5-11. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Diesel units had the greatest variance in EFORD, while nuclear units had the lowest variance in EFORD values in the first three months of 2016.

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 market design is implemented beginning with Delivery Year 2018/2019 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.⁸⁸

⁸⁸ "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 5.B.

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).⁸⁹ 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.⁹⁰ Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC 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.⁹¹ That choice was made by PJM and can be modified without violating any NERC requirements.⁹² 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.

⁸⁹ 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>.

⁹⁰ 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>.

⁹¹ 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 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.

⁹² 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.

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 5-23 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.0 percent of all forced outages in the first three months of 2016. The largest contributor to OMC outages, flood, was the cause of 26.3 percent of OMC outages and 1.1 percent of all forced outages.

Table 5-23 OMC outages: January through March, 2016

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Flood	26.3%	1.1%
Transmission system problems other than catastrophes	22.2%	0.9%
Lack of fuel	21.7%	0.9%
Other switchyard equipment	16.8%	0.7%
Transmission line	4.4%	0.2%
Switchyard circuit breakers	2.8%	0.1%
Transmission equipment at the 1st substation	2.5%	0.1%
Transmission equipment beyond the 1st substation	0.7%	0.0%
Lack of water (hydro)	0.5%	0.0%
Lightning	0.5%	0.0%
Other catastrophe	0.4%	0.0%
Regulatory (environmental) proceedings and hearings	0.3%	0.0%
Switchyard transformers and associated cooling systems	0.3%	0.0%
Switchyard system protection devices	0.2%	0.0%
Storms (ice)	0.1%	0.0%
Other miscellaneous external problems	0.1%	0.0%
Other fuel quality problems	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.⁹³

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 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.

⁹³ 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/JMM_And_PJM_Capacity_White_Papers_On_OPSL_Issues_20120820.pdf> (August 20, 2012).

Performance Incentives

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 market design is implemented beginning with Delivery Year 2018/2019 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 2015, 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 non-performance 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.

$$(\text{PCAP}) \text{ Peak Period Capacity} = \text{ICAP} * (1 - \text{EFORp})$$

$$(\text{TCAP}) \text{ Target Unforced Capacity} = \text{ICAP} * (1 - \text{XEFORd-5})$$

$$\text{Peak Period Capacity Shortfall} = \text{TCAP} - \text{PCAP}$$

The peak-hour period availability charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.⁹⁴

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 to be the XEFORd calculated for the 12 months ending in September in the year prior to the delivery year.⁹⁵

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.⁹⁶

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.⁹⁷

⁹⁴ PJM. OATT Attachment DD § 10 (j).

⁹⁵ PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 4.2.5

⁹⁶ PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.

⁹⁷ PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), Section 8.4.5.1.

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.⁹⁸ 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.⁹⁹

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.¹⁰⁰

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.¹⁰¹

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.

⁹⁸ PJM. OATT Attachment DD § 7.10 (e).

⁹⁹ *Id.*

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

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.¹⁰²

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.¹⁰³ On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).¹⁰⁴

PJM EFOF was 3.8 percent in the first three months of 2016. This means there was 3.8 percent lost availability because of forced outages. Table 5-24 shows that forced outages for boiler tube leaks, at 21.3 percent of the systemwide EFOF, were the largest single contributor to EFOF.

¹⁰² PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015)

¹⁰³ 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.

¹⁰⁴ EFOF incorporates all outages regardless of their designation as OMC.

Table 5-24 Contribution to EFOF by unit type by cause: January through March, 2016

	Combined		Combustion					System
	Cycle	Turbine	Diesel	Hydroelectric	Nuclear	Steam		
Boiler Tube Leaks	3.7%	0.0%	0.0%	0.0%	0.0%	27.8%	21.3%	
Miscellaneous (Balance of Plant)	0.2%	2.2%	0.0%	12.2%	0.0%	11.6%	9.3%	
Miscellaneous (Generator)	1.7%	3.2%	10.0%	7.5%	6.7%	8.1%	7.0%	
Feedwater System	1.2%	0.0%	0.0%	0.0%	0.0%	7.4%	5.7%	
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	7.0%	5.3%	
Economic	1.5%	35.5%	3.8%	4.5%	0.0%	1.3%	4.3%	
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	4.5%	3.4%	
Valves	7.0%	0.0%	0.0%	0.0%	0.0%	3.1%	3.0%	
Electrical	0.7%	12.0%	3.6%	0.6%	0.0%	2.1%	2.7%	
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	61.2%	0.0%	2.7%	
Reserve Shutdown	2.0%	5.5%	8.4%	21.0%	0.0%	1.8%	2.5%	
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%	2.5%	
Exciter	22.3%	0.8%	0.0%	0.0%	0.0%	0.6%	2.4%	
Auxiliary Systems	4.5%	6.4%	0.0%	2.1%	0.0%	1.9%	2.4%	
Fuel Quality	0.0%	0.0%	4.3%	0.0%	0.0%	2.5%	1.9%	
Controls	1.9%	0.7%	0.9%	0.9%	23.2%	0.5%	1.7%	
Condensate System	0.7%	0.0%	0.0%	0.0%	0.1%	1.9%	1.5%	
Condensing System	0.1%	0.0%	0.0%	0.0%	0.0%	1.9%	1.4%	
Boiler Piping System	2.2%	0.0%	0.0%	0.0%	0.0%	1.6%	1.4%	
All Other Causes	49.9%	33.6%	69.0%	51.1%	8.8%	11.2%	17.5%	
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	

Table 5-25 shows the categories which are included in the economic category.¹⁰⁵ Lack of fuel that is considered outside management control accounted for 20.5 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.”¹⁰⁶ 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.

¹⁰⁵ The definitions of these outages are defined by NERC GADS.

¹⁰⁶ The definitions of these outages are defined by NERC GADS.

Table 5-25 Contributions to Economic Outages: January through March, 2016

Contribution to Economic Reasons	
Lack of fuel (Non-OMC)	73.1%
Lack of fuel (OMC)	20.5%
Fuel conservation	3.4%
Other economic problems	2.0%
Lack of water (hydro)	0.5%
Wet fuel (biomass)	0.5%
Ground water or other water supply problems	0.0%
Problems with primary fuel for units with secondary fuel operation	0.0%
Total	100.0%

EFORD, XEFORD and EFORp

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

Until the Capacity Performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of non-performance 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.¹⁰⁷ 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 combustion turbines and nuclear units,

¹⁰⁷ See PJM, “Manual 22: Generator Resource Performance Indices,” Revision 16 (November 16, 2011), Definitions.

EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORP metric.

Table 5-26 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for combustion turbine units.

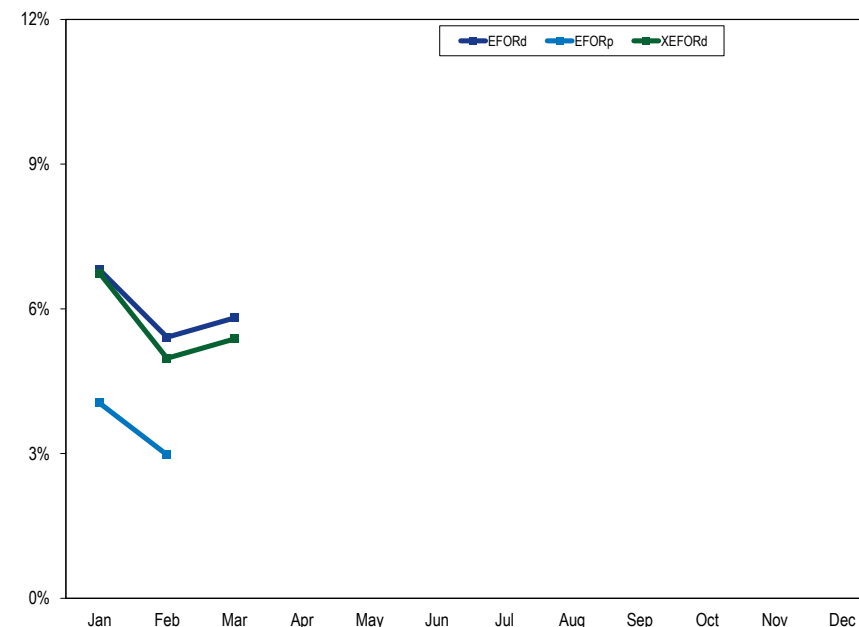
Table 5-26 PJM EFORd, XEFORd and EFORp data by unit type: January through March, 2016¹⁰⁸

				Difference	Difference
	EFORd	XEFORd	EFORp	EFORd and XEFORd	EFORd and EFORp
Combined Cycle	2.6%	2.4%	1.6%	0.2%	1.0%
Combustion Turbine	8.5%	8.0%	2.9%	0.5%	5.6%
Diesel	8.0%	7.5%	4.1%	0.5%	3.9%
Hydroelectric	3.1%	2.3%	2.8%	0.8%	0.3%
Nuclear	1.0%	1.0%	1.2%	0.0%	(0.2%)
Steam	8.8%	8.4%	5.8%	0.4%	3.0%
Total	6.0%	5.7%	3.6%	0.3%	2.3%

Performance By Month

On a monthly basis, EFORp values were significantly 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: January through March, 2016



¹⁰⁸ EFORp is only calculated for the peak months of January, February, June, July and August.

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: January through March, 2016

