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 meet their obligations in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2011, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

Table 4-1 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: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. 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.[1]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs failed the TPS which is conducted at the time of the auction.[2]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a planned resource 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, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and a definition of DR which permits inferior products to substitute for capacity.

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.[3]

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.[4] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined

1 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

2 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.

3 The terms *PJM Region, RTO Region* and *RTO* are synonymous in the *2011 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.

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

that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[5] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. 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.[6]

RPM prices are locational and may vary depending on transmission constraints.[7] 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. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side 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 calendar year 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 178,846.5, primarily due to the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of calendar year 2011, 42.0 percent was coal; 28.3 percent was gas; 18.2 percent was nuclear; 6.3 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.
- **Supply.** Total internal capacity increased 851.8 MW from 159,030.9 MW on June 1, 2010, to 159,882.7 MW on June 1, 2011. This increase was the result of the classification of Duquesne resources as external at the time of the 2011/2012 RPM Base Residual Auction (-3,006.6 MW), new generation (2,203.7 MW), reactivated generation (486.9 MW), net generation capacity modifications (cap mods) (439.0 MW), Demand Resource (DR) modifications (684.4 MW), and the EFORd effect due to lower sell offer EFORds (44.4 MW).
- **Demand.** There was a 2,385.7 MW decrease in the RPM reliability requirement from 156,636.8 MW on June 1, 2010, to 154,251.1 MW on June 1, 2011. This decrease was due to the exclusion of the Duquesne Zone from the preliminary forecast peak load for the 2011/2012 RPM Base Residual Auction. On June 1, 2011, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.4 percent, down from 77.7 percent on June 1, 2010.
- **Market Concentration.** For the 2011/2012, 2012/2013, 2013/2014, and 2014/2015 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2011/2012 RPM First Incremental Auction, 2011/2012 ATSI Integration Auction, 2011/2012 RPM Third Incremental Auction, 2012/2013 RPM First Incremental Auction, 2012/2013 ATSI Integration Auction, 2012/2013 RPM Second Incremental Auction, 2013/2014 BRA, and 2013/2014 RPM First Incremental Auction failed the three pivotal supplier (TPS) market structure test.[8] In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test, and six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 BRA,

5 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
6 See 126 FERC ¶ 61,275 (2009) at P 88.
7 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.
8 As of December 31, 2011, there are 24 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).

all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. 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, would have increased the market clearing price.[9,10,11]

- **Imports and Exports.** Net exchange increased 3,658.3 MW from June 1, 2010 to June 1, 2011. Net exchange, which is imports less exports, increased due to an increase in imports of 3,699.3 MW primarily due to the reclassification of the Duquesne resources, offset by an increase in exports of 11.0 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,005.3 MW from 8,683.0 MW on June 1, 2010 to 9,688.3 MW on June 1, 2011. Demand-side resources include Demand Resources (DR) and Energy Efficiency (EE) resources cleared in RPM Auctions and certified/forecast interruptible load for reliability (ILR). Effective with 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 Resource type is eligible to be offered in RPM Auctions.[12]

Market Conduct

- **2011/2012 RPM Base Residual Auction.**[13] Of the 1,125 generation resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). The MMU calculated offer caps for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) avoidable cost rate (ACR) values.

- **2011/2012 RPM First Incremental Auction.**[14] Of the 129 generation resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). The MMU calculated offer caps for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR values.

- **2011/2012 ATSI Integration Auction.**[15] Of the 141 generation resources which submitted offers, 52 resources elected the offer cap option of 1.1 times the BRA clearing price (36.9 percent). Unit-specific offer caps were calculated for four resources (2.8 percent). The MMU calculated offer caps for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM Third Incremental Auction.** Of the 398 generation resources which submitted offers, 214 resources elected the offer cap option of 1.1 times the BRA clearing price (53.8 percent). Unit-specific offer caps were calculated for zero resources (0.0 percent). The MMU calculated offer caps for 23 resources (5.8 percent), of which 21 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM Base Residual Auction.**[16] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.

- **2012/2013 ATSI Integration Auction.**[17] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). The MMU calculated offer caps 131

9 OATT Attachment DD (Reliability Pricing Model) § 6.5.

10 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.

11 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).

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

13 For a more detailed analysis of the 2011/2012 RPM Base Residual Auction, see "Analysis of the 2011/2012 RPM Auction Revised" <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf> (October 1, 2008).

14 For a more detailed analysis of the 2011/2012 RPM First Incremental Auction, see "Analysis of the 2011/2012 RPM First Incremental Auction" <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf> (January 6, 2011).

15 For a more detailed analysis of the 2011/2012 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf> (January 14, 2011).

16 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009).

17 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf> (January 14, 2011).

resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Second Incremental Auction.** Of the 188 generation resources which submitted offers, unit-specific offer caps were calculated for 8 resources (4.3 percent). The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Base Residual Auction.**[18] Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.** Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.

Market Performance

- Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $135.16 per MW-day in 2011 and then declined to $127.05 per MW-day in 2014.
- RPM net excess increased 2,910.4 MW from 7,728.0 MW on June 1, 2010, to 10,638.4 MW on June 1, 2011.
- For the 2011/2012 planning year, RPM annual charges to load totaled approximately $5.7 billion.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 7.2 percent in 2010 to 7.9 percent in 2011.[19]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 84.9 percent in 2010 to 83.7 percent in 2011.
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2011, 11.6 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any

18 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, 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).

19 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 resources in the RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 26, 2012. 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.

Table 4-2 RPM Related MMU Reports

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf

supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in calendar year 2011. 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 calendar year 2011.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[20,21,22,23] In 2011, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

Detailed Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
  - The MMU recommends that the Short-Term Resource Procurement Target (2.5 percent demand offset) be eliminated.
  - The MMU recommends that the definition of demand side capacity (Demand Response (DR)) resources be made comparable to generation capacity resources to ensure that all resources provide the same value in the capacity market. The DR product should be defined to require unlimited interruptions.
  - The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. PJM is addressing some of these barriers to entry.
  - 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.
  - 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.
  - The MMU recommends that PJM use the most current Handy Whitman Index value to recalculate the ACR for the applicable year and update the ten year annual average Handy Whitman Index value to recalculate the subsequent default ACR values.
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
  - The MMU recommends that there be an explicit requirement that capacity unit offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
  - The MMU recommends that protocols be defined for recalling the energy output of capacity resources when PJM is in an emergency condition. PJM is developing these protocols.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
  - The MMU recommends that PJM review all requests for Out of Management Control (OMC) carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends

20 See "Analysis of the 2011/2012 RPM Auction Revised" <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf> (October 1, 2008).

21 See "Analysis of the 2012/2013 RPM Base Residual Auction" <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009)

22 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).

23 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf> (October 4, 2010).

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2011

	1-Jan-11		31-May-11		1-Jun-11		31-Dec-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,879.4	40.7%	76,968.3	42.4%	75,190.4	42.0%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,529.3	28.3%
Hydroelectric	7,954.5	4.8%	7,991.8	4.8%	8,029.6	4.4%	8,047.0	4.5%
Nuclear	30,552.2	18.4%	30,822.2	18.5%	33,145.6	18.3%	32,492.6	18.2%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,217.3	6.3%
Solar	0.0	0.0%	1.9	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	633.5	0.3%	649.5	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	178,846.5	100.0%

that PJM propose eliminating lack of fuel as an acceptable basis for an OMC outage.

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.
  - The MMU recommends that the RMR requirements be modified to make RMR service mandatory.
  - The MMU recommends that the notice period for retirement be extended from 90 days to at least one year and that both PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses.
  - The MMU recommends that treatment of costs in RMR filings be clarified. Customers should bear all the incremental costs, including 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.
  - The MMU recommends that RMR agreements should limit customers' payment obligations to the costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed.

Installed Capacity

On January 1, 2011, PJM installed capacity was 166,410.2 MW (Table 4-3).[24] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 166,611.9 MW on May 31, 2011, an increase of 201.7 MW or 0.1 percent over the January 1 level.[25]

At the beginning of the new planning year on June 1, 2011, PJM installed capacity was 181,438.7, an increase of 14,826.8 MW or 8.9 percent over the May 31 level. Of the 14,826.8 MW change from May 31 to June 1, 13,481.6 MW were due to the integration of the ATSI Zone.

On December 31, 2011, PJM installed capacity was 178,846.5 MW.[26]

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.

24 Percent values shown in Table 4-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

25 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.

26 Wind-based resources accounted for 649.5 MW of installed capacity in PJM on December 31, 2011. 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 in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Annual base auctions are held in May for delivery years that are three years in the future. Prior to January 31, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[27] In calendar year 2011, a Third Incremental Auction was held in February for the 2011/2012 Delivery Year, the a Base Residual Auction was held in May for the 2014/2015 Delivery Year, a Second Incremental Auction was held in July for the 2012/2013 Delivery Year, and a First Incremental Auction was held in September for the 2013/2014 Delivery Year.[28]

Market Structure

Supply

As shown in Table 4-4, total internal capacity increased 851.8 MW from 159,030.9 MW on June 1, 2010, to 159,882.7 MW on June 1, 2011. This increase was the result of the classification of Duquesne resources as external at the time of the 2011/2012 RPM Base Residual Auction (-3,006.6 MW), new generation (2,203.7 MW), reactivated generation (486.9 MW), net generation capacity modifications (cap mods) (439.0 MW), Demand Resource (DR) modifications (684.4 MW), and the EFORd effect due to lower sell offer EFORds (44.4 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2012/2013, 2013/2014, and 2014/2015 auctions, new generation increased 2,928.4 MW; 8.1 MW were reactivated generation and net generation cap mods were -3,598.6 MW. DR and Energy Efficiency (EE) modifications totaled 17,665.5 MW through June 1, 2014. A decrease of 1,805.1 MW was due to higher EFORds, and an increase of 6.8 MW was due to a higher Load Management UCAP conversion factor. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity, the integration of the ATSI Zone resources added 13,175.2 MW to total internal capacity, and the integration of the DEOK Zone resources added 4,816.8 MW to total internal capacity. A decrease of 31.2 MW was due to a correction in resource modeling. The net effect from June 1, 2011, through June 1, 2014, was an increase in total internal capacity of 36,353.1 MW (22.9 percent) from 159,882.7 MW to 196,235.8 MW.

As also shown in Table 4-13, in the 2011/2012 auction, the increase of 21 generation resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

As shown in Table 4-14, in the 2012/2013 auction, the increase of eight generation resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[29] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

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

28 Delivery years are from June 1 through May 31. The 2011/2012 Delivery Year runs from June 1, 2011, through May 31, 2012.

29 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

Table 4-4 Internal capacity: June 1, 2010 to June 1, 2014[30]

	UCAP (MW)							
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco
Total internal capacity @ 01-Jun-10	159,030.9							
Classification of Duquesne resources to external	(3,006.6)							
New generation	2,203.7							
Reactivated generation	486.9							
Generation cap mods	439.0							
DR mods	684.4							
EFORd effect	44.4							
DR and EE effect	0.0							
Total internal capacity @ 01-Jun-11	159,882.7	66,329.7	32,733.0	11,684.2	1,460.3	7,425.8	4,167.5	
Reclassification of Duquesne resources to internal	3,187.2	0.0	0.0	0.0	0.0	0.0	0.0	
New generation	785.5	173.1	59.7	0.0	0.0	0.0	0.0	
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(1,637.3)	(1,012.5)	(444.9)	(540.0)	(31.8)	(379.2)	(509.0)	
DR mods	8,028.7	3,829.7	1,480.9	1,076.9	64.6	423.3	67.6	
EE mods	652.5	186.9	24.4	162.3	0.0	4.1	0.9	
EFORd effect	(944.1)	(502.1)	(185.1)	47.3	5.8	(42.6)	18.3	
DR and EE effect	(1.9)	(0.9)	(0.5)	(0.4)	0.0	0.0	0.0	
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	12,430.3	1,498.9	7,431.4	3,745.3	5,416.0
Correction in resource modeling	0.0	13.0	0.0	0.0	81.3	0.0	28.5	0.0
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5	12,430.3	1,580.2	7,431.4	3,773.8	5,416.0
Integration of existing ATSI resources	13,175.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New generation	1,104.4	172.5	110.3	1.8	0.0	108.8	101.9	1.8
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Generation cap mods	(969.4)	(1,007.7)	(884.9)	(113.8)	12.4	(180.2)	(180.2)	(11.0)
DR mods	1,894.1	900.2	689.5	(207.4)	9.7	646.1	431.2	61.8
EE mods	100.8	(34.9)	(0.3)	(51.9)	(8.1)	3.3	(0.3)	(20.7)
EFORd effect	(589.3)	27.7	117.5	(292.5)	18.1	26.0	48.3	(159.4)
DR and EE effect	9.1	4.2	1.0	1.8	0.1	0.2	0.1	0.4
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9
Correction in resource modeling	(31.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adjusted internal capacity @ 01-Jun-13	184,647.0	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9
Integration of existing DEOK resources	4,816.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New generation	1,038.5	875.8	697.2	2.7	48.0	6.8	1.5	0.0
Reactivated generation	8.1	8.1	8.1	0.0	0.0	8.1	0.0	0.0
Generation cap mods	(991.9)	(175.2)	(102.3)	(242.8)	(161.9)	9.3	(0.5)	(2.8)
DR mods	6,940.0	6,653.8	2,438.6	2,727.5	241.9	547.0	205.0	681.7
EE mods	49.4	55.6	1.2	52.0	3.0	(0.6)	(0.6)	7.5
EFORd effect	(271.7)	(248.0)	(93.5)	54.1	(17.8)	104.8	25.5	106.4
DR and EE effect	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total internal capacity @ 01-Jun-14	196,235.8	76,249.0	36,649.9	14,361.8	1,725.6	8,711.0	4,405.7	6,081.7

Table 4-5 RPM generation capacity additions: 2007/2008 through 2014/2015

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
2014/2015	1,102.8	9.0	499.5	1,096.7	2,708.0
Total	7,088.9	858.7	5,404.8	5,222.8	18,575.2

30 The RTO includes MAAC, EMAAC and SWMAAC. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South, PSEG and PSEG North. SWMAAC includes Pepco.

As shown in Table 4-15, in the 2013/2014 auction, the increase of 37 generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 Delivery Year: four wind resources (66.2 MW).

As shown in Table 4-16, in the 2014/2015 auction, the 43 additional generation resources offered consisted of 39 new resources (1,038.5 MW), two additional resources imported (577.6 MW), one reactivated resource (8.1 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource (22.5 MW). The new Generation Capacity Resources consisted of 17 solar resources (30.2 MW), seven wind resources (146.6 MW), seven diesel resources (31.5 MW), five hydroelectric resources (132.7), two CT units (76.7 MW), and one combined cycle unit (620.8 MW). The reactivated Generation Capacity Resources consisted of one diesel resource (8.1 MW). The 61 fewer generation resources offered consisted of 12 deactivated resources (936.8 MW), 12 additional resources excused from offering (1,129.9 MW), 32 additional resources committed fully to FRR (2,175.0 MW), four Planned Generation Capacity Resources not offered (240.0 MW), and one external generation resource not offered (6.6 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2013/2014 BRA: two combustion turbine (CT) units (2.5 MW).

Table 4-5 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (7,088.9 MW), reactivated generation capacity resources (858.7 MW), uprates to existing generation capacity resources (5,404.8 MW), and the net increase in capacity imports (5,222.8 MW) totals 18,575.2 MW since the implementation of the Reliability Pricing Model.

Demand

There was a 2,385.7 MW decrease in the RPM reliability requirement from 156,636.8 MW on June 1, 2010, to 154,251.1 MW on June 1, 2011. This decrease was due to the exclusion of the Duquesne Zone from the preliminary forecast peak load for the 2011/2012 RPM Base Residual Auction.

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.

Table 4-6 PJM Capacity Market load obligation served: June 1, 2011

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	56,439.0	26,131.5	24,786.6	1,290.5	17,884.5	138.3	23,757.2	150,427.7
Percent of total obligation	37.5%	17.4%	16.5%	0.9%	11.9%	0.1%	15.8%	100.0%

On June 1, 2011, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.4 percent (Table 4-6), down from 77.7 percent on June 1, 2010. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.6 percent, up from 22.3 percent on June 1, 2010. Prior to the 2012/2013 Delivery Year, obligation is defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective 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.

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT), the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions.[31] The results of the PMSS are applicable for all RPM Auctions for the given delivery year.[32] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the application of market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[33]

Table 4-7 Preliminary market structure screen results: 2011/2012 through 2014/2015 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail

As shown in Table 4-7, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data or opportunity cost data to the MMU for resources for which they intended to submit a non-zero sell offer price unless certain other conditions were met.[34]

31 OATT Attachment M (PJM Market Monitoring Plan)-Appendix § II.D.1.
32 OATT Attachment DD § 5.11 (b).
33 OATT Attachment M-Appendix § II.D.2.
34 OATT Attachment DD § 6.7 (c).

Auction Market Structure

As shown in Table 4-8, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2011/2012 BRA, the 2011/2012 RPM First Incremental Auction, the 2011/2012 ATSI FRR Integration Auction, 2011/2012 RPM Third Incremental Auction, the 2012/2013 RPM First Incremental Auction, the 2012/2013 ATSI FRR Integration Auction, the 2012/2013 RPM Second Incremental Auction, the 2013/2014 BRA, and the 2013/2014 RPM First Incremental Auction.[35] The result was that 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 the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. In the 2014/2015 BRA, all participants included in the incremental supply in MAAC passed the test. 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.[39] 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 4-8 RSI results: 2011/2012 through 2014/2015 RPM Auctions[40]

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First Incremental Auction			
RTO	0.62	30	30
2011/2012 ATSI FRR Integration Auction			
RTO	0.07	21	21
2011/2012 Third Incremental Auction			
RTO	0.41	52	52
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3
2012/2013 ATSI FRR Integration Auction			
RTO	0.10	16	16
2012/2013 First Incremental Auction			
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.60	25	25
EMAAC	0.00	2	2
2012/2013 Second Inremental Auction			
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.64	33	33
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1
2013/2014 First Incremental Auction			
RTO/MAAC	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.00	3	3
SWMAAC/Pepco	0.00	0	0
2014/2015 BRA			
RTO	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.03	7	0
PSEG North	0.00	1	1

Table 4-8 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 (RSI_3). The RSI_x is a general measure that can be used with any number

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 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).

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

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

of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM 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 outside PJM.[41]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability is assured by the requirements for firm transmission service. 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 another reason 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.

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.[42,43] 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 Market.[44]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Market must be scheduled to physically flow in the Real-Time Market. When submitting the Real-Time 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 Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

41 OATT Attachment DD § 5.6.6(b).

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

43 See PJM. "Manual 18: PJM Capacity Market", Revision 13 (November 17, 2011), pp. 23-25 & p. 43.

44 OATT, Schedule 1, Section 1.10.1A.

Table 4-9 PJM capacity summary (MW): June 1, 2007 to June 1, 2014[45]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,299.4
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,243.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	3,056.3
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4
EE cleared						568.9	679.4	822.1
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6			
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[46,47] 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.[48] 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.[49]

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.[50] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[51]

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.[52]

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.

As shown in Table 4-9, net exchange increased 3,658.3 MW from June 1, 2010 to June 1, 2011. Net exchange, which is imports less exports, increased due to an increase in imports of 3,699.3 MW primarily due to the

45 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

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

47 See PJM. "Manual 18: PJM Capacity Market", Revision 13 (November 17, 2011), pp. 26-27.

48 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).

49 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).

50 OATT Attachment DD § 6.6(g).

51 *Id.*

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

reclassification of the Duquesne resources, offset by an increase in exports of 11.0 MW.

Demand-Side Resources

There are three basic demand side products incorporated in the RPM market design:[53]

- **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 as of the 2012/2013 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. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption 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 such delivery year, without any requirement of notice, dispatch, or operator intervention.[54] The Energy Efficiency (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.[55]

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated into the RPM market design:[56,57]

- **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 at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for at least a 10-hour duration 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 at least a 6-hour duration during the hours of 12:00 p.m. to 8:00 p.m. EPT.

As shown in Table 4-10 and Table 4-12, capacity in the RPM load management programs increased by 1,005.3 MW from 8,683.0 MW on June 1, 2010 to 9,688.3 MW on June 1, 2011. Table 4-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement transactions along with certified ILR.

Market Conduct

Offer Caps

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, increased the market clearing price.[58,59,60]

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate

53 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.

54 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 6, Section M.

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

56 134 FERC ¶ 61,066 (2011).

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

58 See OATT Attachment DD § 6.5.

59 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.

60 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 4-10 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[61,62,63]

	UCAP (MW)							
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco
DR cleared	962.9	918.5		520.8	14.9			
DR net replacements	(516.3)	(480.9)		(112.7)	(14.9)			
ILR	8,236.4	3,113.7		655.2	168.4			
RPM load management @ 01-Jun-10	8,683.0	3,551.3		1,063.3	168.4			
DR cleared	1,826.6							
EE cleared	76.4							
DR net replacements	(1,247.5)							
EE net replacements	0.2							
ILR	9,032.6							
RPM load management @ 01-Jun-11	9,688.3							
DR cleared	7,732.9	4,939.9	1,836.5	1,778.8	97.2	497.7	121.9	
EE cleared	585.6	187.5	27.6	159.7	0.0	4.5	1.2	
DR net replacements	(179.2)	(114.2)	0.0	(86.4)	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-12	8,139.3	5,013.2	1,864.1	1,852.1	97.2	502.2	123.1	
DR cleared	9,802.4	6,005.2	2,588.4	1,650.3	146.1	1,183.8	534.8	547.8
EE cleared	748.6	204.5	55.2	113.5	2.0	25.8	9.2	36.7
DR net replacements	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
RPM load management @ 01-Jun-13	10,551.0	6,209.7	2,643.6	1,763.8	148.1	1,209.6	544.0	584.5
DR cleared	14,118.4	7,236.8	2,866.8	2,234.4	220.9	964.2	443.3	893.1
EE cleared	822.1	199.6	20.9	161.3	5.0	4.8	0.0	42.9
DR net replacements	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
RPM load management @ 01-Jun-14	14,940.5	7,436.4	2,887.7	2,395.7	225.9	969.0	443.3	936.0

Table 4-11 RPM load management cleared capacity and ILR: 2007/2008 through 2014/2015[64,65,66]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	7,487.9	7,732.9	567.5	585.6	0.0	0.0
2013/2014	9,487.2	9,802.4	726.3	748.6	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

61 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.

62 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

63 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

64 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.

65 FRR committed load management resources are not included in this table.

66 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

Table 4-12 RPM load management statistics: June 1, 2007 to June 1, 2014[67,68]

	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	(1,205.8)	(1,247.5)	0.2	0.2	9,365.1	9,688.3
01-Jun-12	8,055.4	8,318.5	(173.5)	(179.2)	0.0	0.0	7,881.9	8,139.3
01-Jun-13	10,213.5	10,551.0	0.0	0.0	0.0	0.0	10,213.5	10,551.0
01-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

Table 4-13 ACR statistics: 2011/2012 RPM Auctions

	2011/2012 Base Residual Auction		2011/2012 First Incremental Auction		2011/2012 ATSI Integration Auction		2011/2012 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	299	26.6%	44	34.1%	57	40.4%	21	5.3%
ACR data input (APIR)	133	11.8%	18	14.0%	4	2.8%	0	0.0%
ACR data input (non-APIR)	12	1.1%	1	0.8%	0	0.0%	0	0.0%
Opportunity cost input	24	2.1%	2	1.6%	3	2.1%	2	0.5%
Default ACR and opportunity cost	2	0.2%	3	2.3%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	52	36.9%	214	53.8%
Uncapped planned uprate and default ACR	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned uprate and price taker	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	1	0.3%
Uncapped planned generation resources	20	1.8%	1	0.8%	5	3.5%	27	6.8%
Price takers	635	56.4%	60	46.5%	20	14.2%	133	33.4%
Total Generation Capacity Resources offered	1,125	100.0%	129	100.0%	141	100.0%	398	100.0%

for one year, in particular the delivery year.[69] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed 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.[70]

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, the Generation Capacity Resource does not clear in the RPM market, and if the resource is internal to PJM, it is available for export.

67 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.

68 FRR committed load management resources are not included in this table.

69 OATT Attachment DD § 6.8 (b).

70 OATT Attachment DD § 6.8 (a).

Table 4-14 ACR statistics: 2012/2013 RPM Auctions

	2012/2013 Base Residual Auction		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2012/2013 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	465	41.0%	117	67.6%	92	56.8%	80	42.6%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	8	4.3%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	0	0.0%
Default ACR and opportunity cost	14	1.2%	0	0.0%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA	NA	NA	3	1.6%
Uncapped planned uprate and opportunity cost	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned uprate and price taker	NA	NA	NA	NA	NA	NA	2	1.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	12	6.4%
Price takers	515	45.5%	16	9.2%	37	22.8%	83	44.1%
Total Generation Capacity Resources offered	1,133	100.0%	173	100.0%	162	100.0%	188	100.0%

Table 4-15 ACR statistics: 2013/2014 RPM Auctions

	2013/2014 Base Residual Auction		2013/2014 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	580	49.6%	70	36.5%
ACR data input (APIR)	92	7.9%	27	14.1%
ACR data input (non-APIR)	15	1.3%	0	0.0%
Opportunity cost input	6	0.5%	0	0.0%
Default ACR and opportunity cost	7	0.6%	4	2.1%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	NA	NA	3	1.6%
Uncapped planned uprate and opportunity cost	NA	NA	0	0.0%
Uncapped planned uprate and price taker	NA	NA	1	0.5%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	20	1.7%	1	0.5%
Price takers	450	38.5%	86	44.8%
Total Generation Capacity Resources offered	1,170	100.0%	192	100.0%

Table 4-16 ACR statistics: 2014/2015 RPM Auctions

	2014/2015 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	544	47.2%
ACR data input (APIR)	138	12.0%
ACR data input (non-APIR)	3	0.3%
Opportunity cost input	7	0.6%
Default ACR and opportunity cost	6	0.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	11	1.0%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	6	0.5%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	22	1.9%
Price takers	415	36.0%
Total Generation Capacity Resources offered	1,152	100.0%

Table 4-17 APIR statistics: 2011/2012 RPM Auctions[71,72,73,74]

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2011/2012 BRA							
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54	$75.61
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78	$169.93
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$17.64
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03	$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06	$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97	$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68	$324.58
	Maximum APIR effect						$523.26
2011/2012 First IA							
Non-APIR units	ACR	$54.15	$29.43	NA	$284.63	$30.04	$169.77
	Net revenues	$220.31	$44.98	NA	$298.96	$0.07	$195.83
	Offer caps	$2.66	$2.64	NA	$150.63	$29.97	$83.01
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA	$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA	$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA	$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA	$170.61
	Maximum APIR effect						$468.26

Table 4-18 APIR statistics: 2012/2013 RPM Auctions

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2012/2013 BRA							
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18	$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96	$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$13.74
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA	$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA	$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA	$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA	$351.74
	Maximum APIR effect						$1,155.57
2012/2013 First IA							
Non-APIR units	ACR	$69.71	$30.49	$86.40	$229.86	$32.75	$67.26
	Net revenues	$136.19	$5.75	$12.73	$156.50	$33.52	$30.71
	Offer caps	$32.88	$24.75	$73.67	$75.99	$27.72	$37.81
APIR units	ACR	NA	$50.56	$289.38	$660.56	NA	$367.75
	Net revenues	NA	$9.15	$50.16	$434.48	NA	$138.16
	Offer caps	NA	$41.40	$239.21	$226.09	NA	$229.59
	APIR	NA	$7.70	$156.87	$459.80	NA	$222.35
	Maximum APIR effect						$549.57
2012/2013 Second IA							
Non-APIR units	ACR	$74.06	$31.12	$79.84	$227.16	$51.67	$69.74
	Net revenues	$147.66	$5.80	$4.07	$168.42	$730.19	$47.41
	Offer caps	$30.59	$25.32	$75.77	$69.17	$12.26	$38.04
APIR units	ACR	NA	$141.07	$258.56	$688.62	NA	$404.23
	Net revenues	NA	$15.37	$19.07	$501.86	NA	$186.44
	Offer caps	NA	$125.68	$239.49	$186.76	NA	$217.78
	APIR	NA	$36.84	$89.20	$467.52	NA	$218.87
	Maximum APIR effect						$477.32

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

72 This table has been updated since the MMU RPM Auction reports were posted. The 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.

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

74 Statistics for the 2011/2012 Third Incremental Auction are not included as the majority of the resources elected the offer cap option of 1.1 times the BRA clearing price.

Table 4-19 APIR statistics: 2013/2014 RPM Auctions

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2013/2014 BRA							
Non-APIR units	ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
	Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
	Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units	ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
	Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
	Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
	APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
	Maximum APIR effect						$1,304.36
2013/2014 First IA							
Non-APIR units	ACR	$38.49	$61.44	$151.08	$229.06	$51.00	$146.81
	Net revenues	$13.95	$13.45	$2.05	$132.63	$352.30	$79.75
	Offer caps	$27.94	$48.02	$149.04	$96.88	$21.59	$71.30
APIR units	ACR	NA	$44.20	$445.02	$528.57	NA	$426.53
	Net revenues	NA	$0.84	$74.60	$380.16	NA	$266.48
	Offer caps	NA	$43.36	$370.40	$148.41	NA	$160.05
	APIR	NA	$12.56	$295.56	$329.36	NA	$265.55
	Maximum APIR effect						$593.49

Table 4-20 APIR statistics: 2014/2015 RPM Auction

		Weighted-Average ($ per MW-day UCAP)					
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
2014/2015 BRA							
Non-APIR units	ACR	$47.04	$34.61	$84.19	$222.70	$58.86	$110.52
	Net revenues	$112.21	$29.80	$14.52	$306.01	$226.46	$152.35
	Offer caps	$8.92	$16.34	$74.66	$28.52	$16.68	$25.32
APIR units	ACR	NA	$65.34	$278.46	$511.79	$330.13	$437.99
	Net revenues	NA	$18.24	$55.97	$222.06	$138.36	$182.98
	Offer caps	NA	$51.46	$222.49	$313.68	$191.78	$274.45
	APIR	NA	$38.99	$185.24	$313.37	$1.67	$268.95
	Maximum APIR effect						$744.80

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 CC and 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.[76]

2011/2012 RPM Base Residual Auction

As shown in Table 4-13, 1,125 generation resources submitted offers in the 2011/2012 RPM Base Residual Auction as compared to 1,104 generation resources offered in the 2010/2011 RPM Base Residual Auction. Unit specific offer caps were calculated for 145 resources (12.9 percent of all generation resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. The MMU calculated offer caps for 470 resources (41.8 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 20 planned generation resources had uncapped offers (1.8 percent), while the remaining 635 generation resources were price takers (56.4 percent), of which the offers for

75 135 FERC ¶ 61,022 (2011).

76 FERC subsequently issued an order on November 17, 2011, which included clarification on the duration of mitigation and which resources are subject to the MOPR. See 137 FERC ¶ 61,145 (2011).

578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[77]

Of the 1,125 generation resources which submitted offers, 133 (11.8 percent) included an APIR component. As shown in Table 4-17, the weighted average gross ACR for resources with APIR ($424.49 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($147.77 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $324.58 per MW-day to the ACR value of the APIR resources.[78] The default ACR values included an average APIR of $0.91 per MW-day. The highest APIR for a technology ($578.47 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM First Incremental Auction

As shown in Table 4-13, 129 generation resources submitted offers in the 2011/2012 RPM First Incremental Auction. Unit specific offer caps were calculated for 19 resources (14.7 percent of all generation resources offered) including 18 resources (14.0 percent) with an APIR component and one resource (0.8 percent) without an APIR component. The MMU calculated offer caps for 68 resources (52.8 percent), of which 47 (36.4 percent) were based on the technology specific default (proxy) ACR values. Of the 129 generation resources, one planned generation resource had an uncapped offer (0.8 percent) while the remaining 60 generation resources were price takers (46.4 percent), of which the offers for 36 resources were zero and the offers for 24 resources were set to zero because no data were submitted.

Of the 129 generation resources which submitted offers, 18 resources (14.0 percent) included an APIR component. As shown in Table 4-17, the weighted-average gross ACR for resources with APIR ($326.57 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($197.67 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $170.61 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($324.31 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($468.26 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2011/2012 ATSI Integration Auction

As shown in Table 4-13, 141 generation resources submitted offers in the 2011/2012 ATSI Integration Auction. Unit-specific offer caps were calculated for four resources (2.8 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values. Of the 141 generation resources, 52 resources elected offer cap option of 1.1 times the BRA clearing price (36.9 percent), 5 planned generation resources had uncapped offers (3.5 percent), while the remaining 20 resources were price takers (14.3 percent), of which the offers for 18 resources were zero and the offers for two resources were set to zero because no data were submitted.

2011/2012 RPM Third Incremental Auction

As shown in Table 4-13, 398 generation resources submitted offers in the 2011/2012 Third Incremental Auction. Unit-specific offer caps were calculated for zero resources (0.0 percent of all generation resources). The MMU calculated offer caps for 23 resources (5.8 percent), of which 21 were based on the technology specific default (proxy) ACR values. Of the 398 generation resources, 214 resources elected offer cap option of 1.1 times the BRA clearing price (53.8 percent), 27 planned generation resources had uncapped offers (6.8 percent), one resource had an uncapped planned uprate along with the 1.1 times the BRA clearing price option for the existing portion (0.3 percent), while the remaining 133 resources were price takers (33.4 percent), of which the offers for 131 resources were zero and the offers for two resources were set to zero because no data were submitted.

2012/2013 RPM Base Residual Auction

As shown in Table 4-14, 1,133 generation resources submitted offers in the 2012/2013 RPM Auction as

77 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

78 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

compared to 1,125 generation resources offered in the 2011/2012 RPM Auction. Unit specific offer caps were calculated for 120 resources (10.6 percent of all generation resources offered) including 118 resources (10.4 percent) with an APIR component and 2 resources (0.2 percent) without an APIR component. The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 (42.3 percent) were based on the technology specific default (proxy) ACR values. Of the 1,125 generation resources, 11 planned generation resources had uncapped offers (1.0 percent), while the remaining 515 generation resources were price takers (45.5 percent), of which the offers for 512 resources were zero and the offers for three resources were set to zero because no data were submitted.[79]

Of the 1,133 generation resources which submitted offers, 118 (10.4 percent) included an APIR component. As shown in Table 4-18, the weighted average gross ACR for resources with APIR ($464.65 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($167.62 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $351.74 per MW-day to the ACR value of the APIR resources.[80] The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 ATSI Integration Auction

As shown in Table 4-14, 173 generation resources submitted offers in the 2012/2013 ATSI Integration Auction. Unit-specific offer caps were calculated for 12 resources (6.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values. Of the 173 generation resources, 26 resources elected offer cap option of 1.1 times the BRA clearing price (15.0 percent), while the remaining 16 resources were price takers (9.3 percent), of which the offers for 13 resources were zero and the offers for three resources were set to zero because no data were submitted.

2012/2013 RPM First Incremental Auction

As shown in Table 4-14, 162 generation resources submitted offers in the 2012/2013 RPM First Incremental Auction. Unit-specific offer caps were calculated for 14 resources (8.6 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values. Of the 162 generation resources, 17 planned generation resources had uncapped offers (10.5 percent), while the remaining 37 resources were price takers (22.9 percent), of which the offers for 24 resources were zero and the offers for 13 resources were set to zero because no data were submitted.

Of the 162 generation resources which submitted offers, 14 resources (8.6 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($367.75 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($229.59 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $222.35 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($459.80 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($549.57 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2012/2013 RPM Second Incremental Auction

As shown in Table 4-14, 188 generation resources submitted offers in the 2012/2013 RPM Second Incremental Auction. Unit-specific offer caps were calculated for 8 resources (4.3 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values. Of the 188 generation resources, 12 planned generation resources had uncapped offers (6.4 percent), three resources had uncapped planned uprates along with default ACR

79 Planned units are subject to mitigation under specific circumstances defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers.

80 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

based offer caps calculated for the existing portion (1.6 percent), two resources had uncapped planned uprates along with price taker status for the existing portion (1.1 percent), while the remaining 83 resources were price takers (44.1 percent), of which the offers for 78 resources were zero and the offers for five resources were set to zero because no data were submitted.

Of the 188 generation resources which submitted offers, 8 resources (4.3 percent) included an APIR component. As shown in Table 4-18, the weighted-average gross ACR for resources with APIR ($404.23 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($217.78 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $218.87 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.31 per MW-day. The highest APIR for a technology ($467.52 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($477.32 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM Base Residual Auction

As shown in Table 4-15, 1,170 generation resources submitted offers compared to 1,133 generation resources offered in the 2012/2013 RPM Base Residual Auction. Unit specific offer caps were calculated for 107 resources (9.1 percent of all generation resources offered) including 92 resources (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 resources (1.3 percent) without an APIR component. The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 (50.2 percent) were based on the technology specific default (proxy) ACR values. Of the 1,170 generation resources, 20 planned generation resources had uncapped offers (1.7 percent), while the remaining 450 generation resources were price takers (38.4 percent), of which the offers for 441 resources were zero and the offers for nine resources were set to zero because no data were submitted.[81]

Of the 1,170 generation resources which submitted offers, 92 (7.9 percent) included an APIR component. As shown in Table 4-19, the weighted-average gross ACR for resources with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($134.44 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.59 per MW-day to the ACR value of the APIR resources.[82] The default ACR values included an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy Whitman Index value. The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM First Incremental Auction

As shown in Table 4-15, 192 generation resources submitted offers in the 2013/2014 RPM First Incremental Auction. Unit-specific offer caps were calculated for 27 resources (14.1 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values. Of the 192 generation resources, one planned generation resources had an uncapped offer (0.5 percent), three resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.6 percent), one resource had an uncapped planned uprate along with price taker status for the existing portion (0.5 percent), while the remaining 86 resources were price takers (44.8 percent), of which the offers for 86 resources were zero and the offers for no resources were set to zero because no data were submitted.

Of the 192 generation resources which submitted offers, 27 resources (14.1 percent) included an APIR component. As shown in Table 4-19, the weighted-average gross ACR for resources with APIR ($426.53 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($160.05 per MW-day) were higher than for resources without an APIR component, including resources for which the default

81 Planned units are subject to mitigation under specific conditions defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

82 The 92 units which had an APIR component submitted $326.7 million for capital projects associated with 10,328.3 MW of UCAP.

ACR value was selected. The APIR component added an average of $265.55 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day. The highest APIR for a technology ($329.36 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($593.49 per MW-day) was the maximum amount by which an offer cap was increased by APIR.

2014/2015 RPM Base Residual Auction

As shown in Table 4-16, 1,152 generation resources submitted offers compared to 1,170 generation resources offered in the 2013/2014 RPM Base Residual Auction. Unit specific offer caps were calculated for 141 resources (12.2 percent of all generation resources offered) including 138 resources (12.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and three resources (0.3 percent) without an APIR component. The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 (47.7 percent) were based on the technology specific default (proxy) ACR values. Of the 1,152 generation resources, 22 planned generation resources had uncapped offers (1.9 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.0 percent), six generation resources had uncapped planned uprates along with price taker status for the existing portion (0.5 percent), while the remaining 415 generation resources were price takers (36.0 percent), of which the offers for 413 generation resources were zero and the offers for two generation resources were set to zero because no data were submitted. The MOPR was applied and the MOPR exception process was applied to two units.

Of the 1,152 generation resources which submitted offers, 138 (12.0 percent) included an APIR component. As shown in Table 4-20, the weighted-average gross ACR for resources with APIR ($437.99 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($274.45 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.95 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.42 per MW-day, which is the average APIR ($1.37 per MW-day) for the previously estimated default ACR values in the 2013/2014 BRA escalated using the most recent Handy Whitman Index value. The highest APIR for a technology ($313.37 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($744.80 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance[83]

The RTO resource clearing price decreased $64.29 per MW-day (36.9 percent) from $174.29 per MW-day for the 2010/2011 BRA to $110.00 per MW-day for the 2011/2012 BRA (Table 4-21).

Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $135.16 per MW-day in 2011 and then declined to $127.05 per MW-day in 2014. Figure 4-1 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 4-9 shows, RPM net excess increased 2,910.4 MW from 7,728.0 MW on June 1, 2010, to 10,638.4 MW on June 1, 2011, because of a 2,040.1 MW decrease in the reliability requirement and a 796.2 MW increase in ILR, offset by an 11.9 MW decreased in cleared capacity.[84] The increase in unforced capacity of 4,510.1 MW was the result of an increase in total internal capacity of 1,712.7 MW plus an increase in imports of 3,669.3 MW primarily due to the reclassification of the Duquesne resources, offset by an increase in exports of 11.0 MW (Table 4-4).[85]

Table 4-22 shows RPM revenue by resource type for all RPM Auctions held to date with over $500 million for new/reactivated resources based on the unforced MW cleared and the resource clearing prices.

83 The MMU provides detailed analyses of market performance in reports for each RPM auction. See <http://www.monitoringanalytics.com/reports/Reports/2012.shtml>.

84 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

85 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

Table 4-21 Capacity prices: 2007/2008 through 2014/2015 RPM Auctions

		RPM Clearing Price ($ per MW-day)							
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$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
2011/2012 BRA		$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
2011/2012 ATSI FRR Integration Auction		$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
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction		$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	$153.67	$16.46	$153.67	$153.67	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50

Table 4-22 RPM revenue by type: 2007/2008 through 2014/2015[86,87]

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$263,534,711	$551,453,434	$666,313,051	$1,703,980,980
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,334,802	$20,680,368	$38,571,074	$70,726,056
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,115,246	$31,191,272	$178,063,746	$653,501,083
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,015,994,058	$1,736,326,997	$1,827,519,210	$14,122,051,712
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,413,749	$12,493,918	$56,917,305	$110,177,869
Gas existing	$1,514,681,896	$1,951,345,311	$2,329,209,917	$2,632,336,161	$1,607,317,731	$1,116,743,821	$1,894,356,673	$2,003,810,846	$15,049,802,356
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,551,231	$166,414,514	$184,029,455	$626,902,467
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,085,726	$308,742,213	$328,877,767	$2,399,748,544
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$17,520	$6,591,114	$6,620,031
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,367	$1,346,024,263	$1,459,911,217	$10,283,710,009
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,951,817	$620,740,652	$433,317,895	$4,075,073,068
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$28,160,593
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,837,739	$43,613,120	$34,529,047	$276,391,712
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$1,190,758	$5,270,804
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,235,710	$2,521,159	$2,371,155	$6,195,001
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,372,110	$1,491,563	$10,190,033
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$4,998,533	$12,898,748	$30,987,962	$83,791,175
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,869,582,961	$6,756,928,604	$7,258,389,284	$49,512,293,493

86 A resource classified as "new/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
87 The results for the ATSI Integrations Auctions are not included in this table.

Figure 4-1 History of capacity prices: Calendar year 1999 through 2014[88]

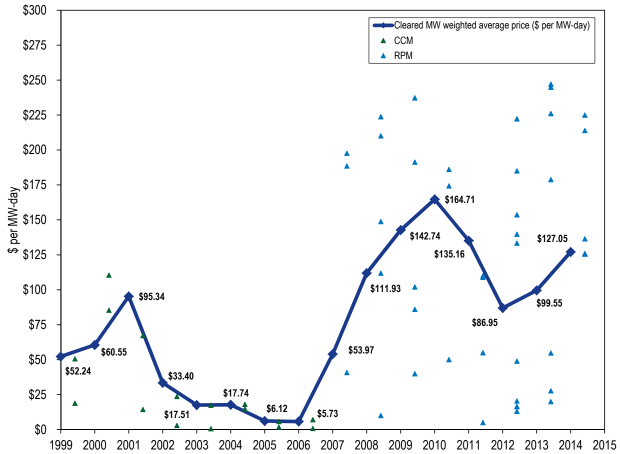


Table 4-23 RPM cost to load: 2011/2012 through 2014/2015 RPM Auctions[89,90,91]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2011/2012			
RTO	$116.15	133,815.3	$5,688,608,837
2012/2013			
RTO	$16.52	67,621.8	$407,745,930
MAAC	$131.48	30,942.6	$1,484,941,563
EMAAC	$141.00	20,476.2	$1,053,813,160
DPL	$169.18	4,584.1	$283,077,133
PSEG	$155.47	12,087.7	$685,916,676
2013/2014			
RTO	$27.86	84,109.2	$855,298,445
MAAC	$227.11	15,244.6	$1,263,707,018
EMAAC	$245.33	37,751.5	$3,380,476,376
SWMAAC	$226.15	8,281.8	$683,617,638
Pepco	$239.36	7,861.0	$686,785,528
2014/2015			
RTO	$125.94	84,581.3	$3,888,042,879
MAAC	$135.25	52,277.4	$2,580,741,594
DPL	$142.99	4,615.4	$240,881,412
PSEG	$164.00	12,208.7	$730,811,202

88 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 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.

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

90 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.

91 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 2012/2013, 2013/2014, and 2014/2015 Net Load Prices are not finalized. The 2012/2013, 2013/2014, and 2014/2015 Obligation MW are not finalized.

Table 4-23 shows the RPM annual charges to load. For the 2011/2012 planning year, RPM annual charges to load totaled approximately $5.7 billion.

Reliability Must Run Units

Part V of the PJM Tariff provides for reliability and market power analyses of power plants proposed for deactivation.[92] An owner may deactivate, meaning either a retirement or mothball, with 90 days notice.[93] PJM performs a reliability analysis to determine whether deactivation would "adversely affect the reliability of the Transmission System absent upgrades," and, if it identified an adverse effect, an "estimate of the ... time it will take to complete the ... upgrades..."[94] The MMU analyses the "effect of the proposed deactivation with regard to market power issues."[95] If PJM determines that a unit is needed for reliability, it would request that the unit provide reliability must run (RMR) service.[96]

The tariff does not require owners to provide RMR service. An owner that agrees to provide RMR service may collect its costs under a formula rate provided in Part V.[97] This rate accounts for "deactivation avoidable costs."[98] An owner may, in the alternative, file with FERC to "recover the entire cost of operating the generating unit."[99]

Units needed for RMR service have market power because only the identified unit(s) can provide the required reliability. As a result, there need to be clear rules governing the payments to RMR generation owners.

RMR Service represents a final period of operation for a unit. During the prior period of market operations, the owner has invested in and maintained the unit and has obtained the best return it could from the markets. Under the market rules, the owner does not have to show that its profits are justified, but it bears the risks associated with cost recovery. RMR service is a consequence of the owner's decision to exit the market when it decides that the unit is no longer economic but the system operator,

92 OATT § 113.2.
93 OATT § 113.1.
94 OATT § 113.2.
95 OATT § Attachment M–Appendix § IV.1.
96 OATT § 113.2.
97 OATT §§ 114, 115.
98 *Id.*
99 OATT § 113.2, 119.

PJM, has determined that continued service is needed for reliability. Customers and not the owner appropriately bear all of the additional costs that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Those costs include a return on and of any additional capital investment required to fulfill the RMR agreement. Customers should not bear any of the costs incurred prior to the decision to retire. Those costs were incurred by the owner based on the owner's responsibility for the consequences. RMR service is not a reason to reverse this basic market principle.[100,101]

The MMU recommends that the RMR requirements be modified to make RMR service mandatory. All market participants have a shared interest in reliability, and a mandatory RMR requirement would ensure that the generation owner is fully compensated for any costs incurred as a result of the RMR requirement.

The MMU recommends that treatment of costs in RMR filings be clarified. Customers should bear all the incremental costs, including 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.

The MMU recommends that the notice period for retirement be extended from 90 days to at least one year and that both PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses.

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 can be measured using indices calculated from historical data. 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).[102]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output had it been running at full nameplate capacity during that period. Nuclear units typically run at a greater than 90 percent capacity factor. In 2011, nuclear units had a capacity factor of 91.7 percent. Combined cycle units ran more often in 2011 than in 2010, going from a 26.8 percent capacity factor in 2010 to a 46.8 percent capacity factor in 2011, indicating combined cycle units had a similar capacity factor to steam units (49.5 percent) in 2011. Due to inexpensive natural gas, this trend may continue, as efficient combined cycle units replace inefficient coal steam units in the PJM footprint.

Table 4-24 PJM capacity factor (By unit type (GWh)); Calendar year 2010 and 2011[103,104]

	2010		2011	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.3	3.5%	0.2	0.3%
Combined Cycle	80,681.4	28.8%	100,485.3	46.8%
Combustion Turbine	8,679.8	3.6%	6,609.2	2.6%
Diesel	864.3	20.5%	716.6	16.4%
Diesel (Landfill gas)	691.3	41.3%	806.3	42.7%
Nuclear	254,534.1	92.3%	262,968.3	91.7%
Pumped Storage Hydro	7,810.5	16.2%	6,885.7	14.3%
Run of River Hydro	6,573.9	32.0%	8,392.3	40.9%
Solar	5.7	14.9%	55.7	12.4%
Steam	375,617.5	53.8%	369,729.6	49.5%
Wind	9,589.6	27.0%	11,561.1	28.9%
Total	745,048.3	48.6%	768,210.2	47.5%

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[105] 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.

100 These issues were raised by the MMU and others in the Exelon RMR filing. See Exelon Generation Company, LLC filing in FERC Docket No. ER10-1418-000 (June 10, 2010). "Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM," "Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM [2nd]," filed in Docket No. ER10-1418-000.

101 132 FERC ¶ 61,219 (2010).

102 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

103 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

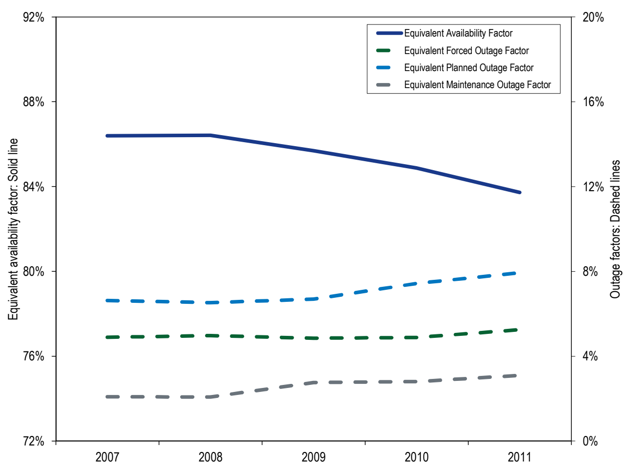
104 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.

105 Data from all PJM capacity resources for the years 2007 through 2011 were analyzed.

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 decreased from 84.9 percent in 2010 to 83.7 percent in 2011. The EMOF increased from 2.8 percent in 2010 to 3.1 percent in 2011, the EPOF increased from 7.4 percent in 2010 to 7.9 percent in 2011, and the EFOF increased from 4.9 percent in 2010 to 5.3 percent in 2011 (Figure 4-2).[106]

Figure 4-2 PJM equivalent outage and availability factors: Calendar years 2007 to 2011

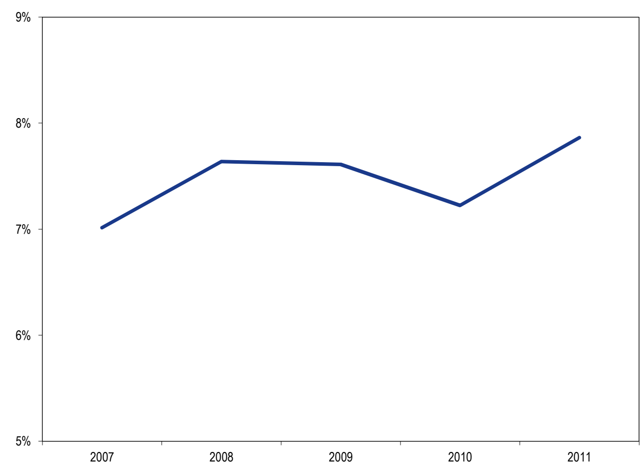


Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) 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 is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's net dependable summer capability.[107] The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

EFORd calculations use historical data, including equivalent forced outage hours,[108] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[109] The average PJM EFORd changed from 7.0 percent in 2007 to 7.6 percent in 2008 and 2009 to 7.2 percent in 2010 to 7.9 percent in 2011. Figure 4-3 shows the average EFORd since 2007 for all units in PJM. The decreases in both EFORd and EAF in 2011 are consistent. EAF decreased as a result of the increase in EPOF, the EMOF and the EFOF. EFORd, on the other hand, describes the forced outage rate during periods of demand, which is a subset of the hours included in EFOF and does not include planned or maintenance outages.

Figure 4-3 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011



106 Data are for the calendar year ending December 31, 2010, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

107 EFORd adjusted to exclude Outside Management Control (OMC) events is defined as XEFORd.

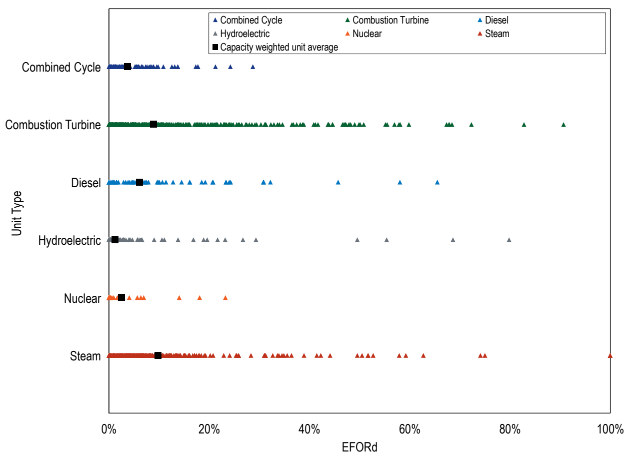
108 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

109 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Equations 2 through 5.

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 4-4. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Steam and combustion turbine units have the greatest variance of EFORd, while nuclear and combined cycle units have the lowest variance in EFORd values.

Figure 4-4 PJM 2011 distribution of EFORd data by unit type



Components of EFORd

Table 4-25 compares PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types.[110]

Table 4-25 PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2007 to 2011

	2007	2008	2009	2010	2011	NERC EFORd 2006 to 2010 Average
Combined Cycle	3.7%	3.8%	4.2%	3.8%	3.2%	5.0%
Combustion Turbine	11.0%	11.1%	9.9%	8.9%	7.8%	9.6%/9.6%
Diesel	11.9%	10.4%	9.3%	6.1%	9.0%	15.8%
Hydroelectric	2.1%	2.0%	3.1%	1.2%	2.2%	5.2%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	3.0%
Steam	9.1%	10.1%	9.4%	9.8%	11.2%	7.6%
Total	7.0%	7.6%	7.6%	7.2%	7.9%	NA

Table 4-26 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[111] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 4-26 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2007 to 2011[112]

	2007	2008	2009	2010	2011	Change in 2011 from 2010
Combined Cycle	0.4	0.5	0.5	0.5	0.4	(0.1)
Combustion Turbine	1.7	1.7	1.6	1.4	1.3	(0.2)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.0
Nuclear	0.3	0.4	0.8	0.5	0.5	0.1
Steam	4.5	5.0	4.7	4.8	5.6	0.8
Total	7.0	7.6	7.6	7.2	7.9	0.6

Steam units continue to be the largest contributor to overall PJM EFORd.

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[113] Figure 4-5 shows the contribution of unit types to system average EFORd. Total capacity in 2011 consists of 70.3 percent baseload capacity, 10.8 percent intermediate capacity, and 18.9 percent peak capacity.

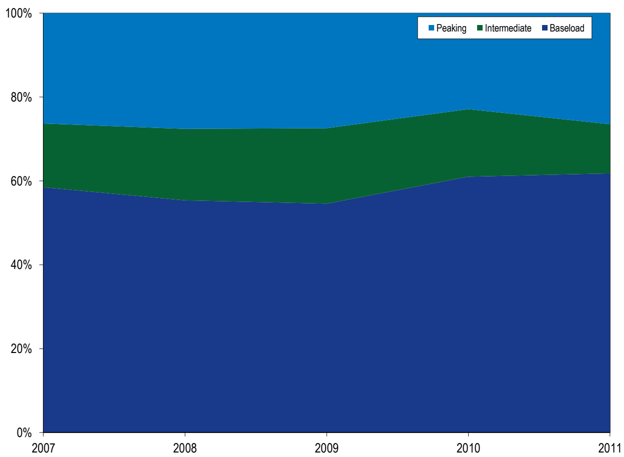
110 NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2006 to 2010 period are 9.6 percent for jet engines and 9.6 percent for gas turbines per NERC's GADS "2006-2010 Generating Unit Statisticl Brochure – Units Reporting Events" <http://www.nerc.com/files/2006-2010_Generating_Unit_Statistical_%20Brochure%20-%20Units_%20Reporting_%20Events%20only.zip>. Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

111 The generating unit types are: combined cycle, combustion turbine, diesel, hydroelectric, nuclear and steam. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

112 Calculated values presented in Section 4, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

113 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

Figure 4-5 Contribution to EFORd by duty cycle: Calendar years 2007 to 2011



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.[114] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

In 2011, PJM EFOF was 5.3 percent. This means there was 5.3 percent lost availability because of forced outages. Table 4-27 shows that forced outages for boiler tube leaks, at 19.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 4-28 shows the categories which are included in the economic category.[115] Lack of fuel that is considered Outside Management Control accounted for 97.0 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 1.7 percent.

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"[116] and was used by 55 combined cycle, combustion turbine and steam units in 2011. Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 4-27 Contribution to EFOF by unit type by cause: Calendar year 2011

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.6%	0.0%	0.0%	0.0%	0.0%	24.3%	19.5%
Electrical	10.2%	15.0%	8.2%	15.0%	12.8%	5.3%	6.8%
Boiler Piping System	13.4%	0.0%	0.0%	0.0%	0.0%	6.9%	6.1%
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	7.4%	5.9%
Economic	0.7%	4.5%	2.6%	3.3%	0.0%	6.7%	5.6%
Catastrophe	0.7%	1.5%	13.7%	21.9%	44.6%	0.6%	4.7%
Feedwater System	2.5%	0.0%	0.0%	0.0%	2.6%	4.9%	4.2%
Generator	1.9%	0.4%	0.7%	3.9%	0.0%	5.0%	4.1%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.0%	4.0%
Circulating Water Systems	3.9%	0.0%	0.0%	0.0%	8.3%	2.2%	2.6%
Reserve Shutdown	3.7%	14.7%	1.6%	0.6%	0.4%	1.5%	2.2%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	2.1%
Miscellaneous (Generator)	9.0%	6.0%	0.9%	3.2%	1.6%	1.2%	1.9%
Fuel Quality	0.0%	0.0%	1.8%	0.0%	0.0%	2.4%	1.9%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	1.8%
Auxiliary Systems	3.2%	14.2%	0.0%	0.2%	0.0%	0.7%	1.5%
Valves	7.4%	0.0%	0.0%	0.0%	0.0%	1.4%	1.5%
Cooling System	0.1%	0.0%	0.2%	8.0%	1.4%	1.5%	1.4%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	14.9%	0.0%	1.3%
All Other Causes	39.2%	43.8%	70.3%	43.9%	13.4%	18.3%	20.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

114 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.

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

116 The classification and definitions of these outages are defined by NERC GADS.

Table 4-28 Contributions to Economic Outages: 2011

	Contribution to Economic Reasons
Lack of fuel (OMC)	97.0%
Lack of fuel (Non-OMC)	1.7%
Lack of water (Hydro)	0.6%
Other economic problems	0.5%
Fuel conservation	0.2%
Problems with primary fuel for units with secondary fuel operation	0.0%
Total	100.0%

Table 4-29 Contribution to EFOF by unit type: Calendar year 2011

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	5.0%
Combustion Turbine	1.9%	5.8%
Diesel	4.2%	0.1%
Hydroelectric	0.7%	1.1%
Nuclear	2.3%	8.6%
Steam	7.7%	79.5%
Total	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units had the largest share (50.1 percent) of PJM capacity, had a high duty cycle and in 2011 had an EFORd of 11.2 percent which yields a 79.5 percent contribution to PJM systemwide EFOF. Using the values in Table 4-29 the contribution of individual unit type causes to PJM systemwide EFOF can be determined. For example, the value for boiler tube leaks in Table 4-27 multiplied by the contribution value in Table 4-29 for the same unit type will yield the percent contribution to the EFOF for that outage cause. Boiler tube leaks contributed 24.3 percent of the EFOF for steam units, total EFOF for steam units was 7.7 percent, which means that boiler tube leaks account for 1.9 percentage points of the 7.7 percent steam unit EFOF.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[117] 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 (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[118] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

All outages, including OMC outages, are included in the EFORd that is used for 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 4-30 shows OMC forced outages by cause code. OMC forced outages account for 11.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 47.3 percent of OMC outages and 5.5 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels." Of the OMC lack of fuel outages in 2011, 97.5 percent of the outages were submitted by units operated by a single owner.

It is questionable whether the OMC outages defined as lack of fuel should be identified as OMC and excluded from the calculation of XEFORd and EFORp. All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU

117 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/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

118 For a list of these cause codes, see the *MMU Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes."

also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

Table 4-30 OMC Outages: Calendar year 2011

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Lack of fuel	47.3%	5.5%
Earthquake	31.2%	3.6%
Tornados	4.1%	0.5%
Transmission system problems other than catastrophes	3.3%	0.4%
Switchyard transformers and associated cooling systems external	3.3%	0.4%
Flood	3.3%	0.4%
Other switchyard equipment external	1.3%	0.2%
Other miscellaneous external problems	0.9%	0.1%
Switchyard system protection devices external	0.9%	0.1%
Transmission line (connected to powerhouse switchyard to 1st Substation)	0.9%	0.1%
Switchyard circuit breakers external	0.8%	0.1%
Lightning	0.8%	0.1%
Storms (ice, snow, etc)	0.6%	0.1%
Hurricane	0.5%	0.1%
Lack of water (hydro)	0.3%	0.0%
Transmission equipment at the 1st substation	0.3%	0.0%
Transmission equipment beyond the 1st substation	0.2%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	11.6%

Table 4-31 shows the impact of OMC outages on EFORd for 2011. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2011 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2011, steam XEFORd was 1.1 percentage points less than EFORd, which translates into a 995 MW difference in unforced capacity.

Table 4-31 PJM EFORd vs. XEFORd: Calendar year 2011

	EFORd	XEFORd	Difference
Combined Cycle	3.2%	3.0%	0.2%
Combustion Turbine	7.8%	6.4%	1.5%
Diesel	9.0%	3.0%	6.0%
Hydroelectric	2.2%	1.7%	0.5%
Nuclear	2.8%	1.6%	1.2%
Steam	11.2%	10.1%	1.1%
Total	7.9%	6.8%	1.0%

Components of 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.

Table 4-32 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 4-32 Contribution to EFORp by unit type (Percentage points): Calendar years 2010 to 2011

	2010	2011
Combined Cycle	0.4	0.2
Combustion Turbine	0.5	0.5
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.5	0.4
Steam	3.8	3.5
Total	5.2	4.7

Table 4-33 PJM EFORp data by unit type: Calendar years 2010 to 2011

	2010	2011
Combined Cycle	3.0%	1.6%
Combustion Turbine	2.9%	3.4%
Diesel	3.3%	2.3%
Hydroelectric	1.1%	1.9%
Nuclear	2.9%	2.1%
Steam	7.7%	7.0%
Total	5.2%	4.7%

EFORd, XEFORd and EFORp

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.[119] 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

119 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their control to do so. That is consistent with the incentives created by the PJM Capacity Market. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 4-34 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 4-35 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 4-34 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2011

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.3	0.2
Combustion Turbine	1.3	1.0	0.5
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.5	0.3	0.4
Steam	5.6	5.1	3.5
Total	7.9	6.8	4.7

Table 4-35 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2011[120]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.2%	3.0%	1.6%	0.2%	1.5%
Combustion Turbine	7.8%	6.4%	3.4%	1.5%	4.4%
Diesel	9.0%	3.0%	2.3%	6.0%	6.7%
Hydroelectric	2.2%	1.7%	1.9%	0.5%	0.3%
Nuclear	2.8%	1.6%	2.1%	1.2%	0.8%
Steam	11.2%	10.1%	7.0%	1.1%	4.2%
Total	7.9%	6.8%	4.7%	1.0%	3.2%

Comparison of Expected and Actual Performance

If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within each unit type and the distribution of EFORd may not be a normal distribution.

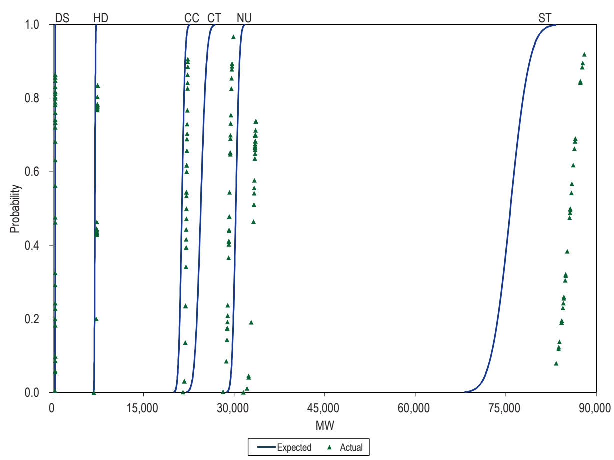
120 EFORp is only calculated for the peak months of January, February, June, July, and August.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the year ending December 31, 2011.[121] These values were used to estimate a normal distribution for each unit type,[122] which was superimposed on a distribution of actual historical availability for the same resources for the year ending December 31, 2011.[123] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 4-6 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, combustion turbine and steam units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

Figure 4-6 PJM 2011 distribution of EFORd data by unit type



121 See "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010), Summer Net Capability.

122 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[MW_i * (1 - EFORd_i)\right]$$

$$\text{Variance} = \sum_i \left[MW_i * MW_i * (1 - EFORd_i) * EFORd_i\right]$$

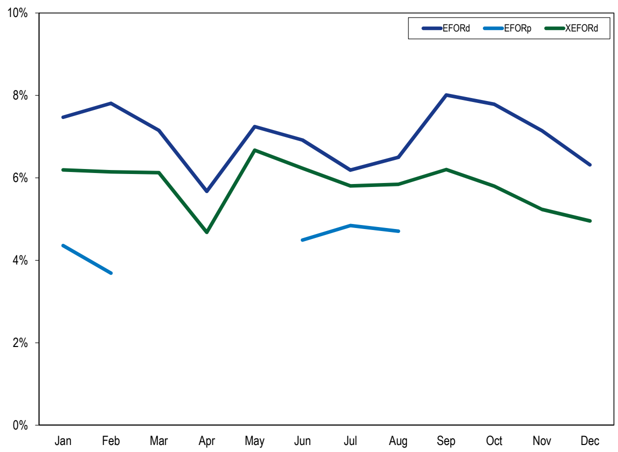
$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

123 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7.

Figure 4-7 PJM EFORd, XEFORd and EFORp: 2011



On a monthly basis, unit availability as measured by the equivalent availability factor increased during the summer months of June, July and August, primarily due to decreasing planned and maintenance outages, as illustrated in Figure 4-8.

Figure 4-8 PJM monthly generator performance factors: 2011