State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2011 State of the Market Report for PJM*.

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

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Introduction

2011 In Review

The state of the PJM markets in 2011 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in 2011. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. There were significant changes in the economic environment of PJM markets in 2011, and of all wholesale power markets, and change will continue in future years. Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. There are still areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

Gas prices fell and coal prices rose in 2011. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. PJM LMPs were lower. The load-weighted average LMP was five percent lower in 2011. PJM capacity prices were lower. PJM average capacity prices were 18 percent lower in 2011. Significant new environmental regulations requiring new emission control technology will take effect in 2015, including MATS and HEDD, affecting current decisions about participation in the capacity market auction to be held in May for the 2015/2016 delivery year.

The results of the market dynamics in 2011 were generally positive for gas fired units, especially new combined cycle units. Total new entrant combined cycle revenues were generally higher in 2011 and exceeded the threshold to incent new entry for most zones.

Five large plants, each over 500 MW, began generating in PJM in 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011. Average offered supply increased by 14,478, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011, including the integration of the ATSI zone in the second quarter.

The results of the market dynamics in 2011 were generally negative for coal fired units, especially older, smaller coal fired units without the required technologies to meet the new environmental regulations. The profitability of coal units declined as a result of declining revenues and increased costs. Market revenues, including capacity market revenues, were not enough to cover even the going forward costs of some of these coal units. The situation was worse for units requiring additional investments to meet environmental regulations.

A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will retire from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. In addition, between 5,764 and 6,936 MW of coal generation is at risk in the PJM market areas that participate in PJM capacity markets.

The PJM capacity market makes the PJM markets more flexible and more able to adapt to the significant changes that are affecting PJM market participants. The use of a forward looking capacity market rather than reliance on real time scarcity pricing to address these issues will permit the adjustment process to occur while reducing risk and dislocations.

The changes in the economic environment make it even more critical to complete the task of getting the design of the capacity market right. In order to ensure that the appropriate market incentives exist to replace retiring units, the capacity market prices must reflect underlying supply and demand fundamentals and especially local supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed. This includes both the 2.5 percent reduction in demand that suppresses market prices and the continued inclusion of inferior demand side products that also suppress market prices. Demand side resources are critical to the success of PJM markets, but they no longer need special treatment. The importance of demand side resources in the capacity market make it more critical that such resources be full capacity resources, required to interrupt whenever called.

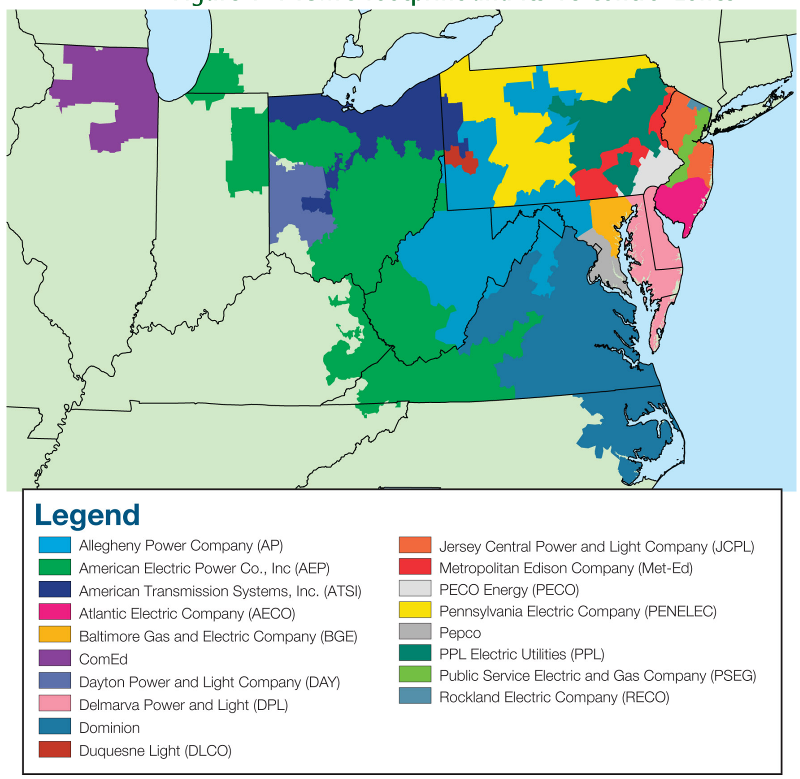
Markets need information in order to function effectively. It is no longer acceptable that generation owners provide only 90 days notice of retirements. That is clearly not enough time for the capacity market to react. Some generation owners have voluntarily provided substantially longer notice. If the higher prices which result from retirements are to provide incentives for required new entry, notice should be at least a year. PJM should consider doing full reliability analyses of all capacity resources at risk, as soon as they are identified, to ensure that locational capacity markets are appropriately defined and that transmission upgrades are completed prior to retirements if appropriate. Continued progress is needed on the transmission interconnection process to ensure that economic generation can be built in a timely manner. State commissions have raised significant questions about whether the capacity market design will maintain local reliability. The market design must be modified to ensure that these questions are answered.

The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants worked constructively to address these challenges in 2011 and will need to continue to do so to ensure the continued effectiveness of PJM markets.

PJM Market Background

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2011, had installed generating capacity of 178,847 megawatts (MW) and more than 750 market buyers, sellers and traders of electricity[1] in a region including more than 58 million people[2] in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3] In 2011, PJM had total billings of $35.9 billion. As part of that market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 18 control zones[4,5]



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and

1 See "Company Overview." PJM.com. PJM Interconnection L.L.C. n.d. 1 January. 2012. <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.

2 See "Company Overview." PJM.com. PJM Interconnection L.L.C. n.d. 1 January. 2012 <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.

3 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.

4 On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint.

5 On January 1, 2012, the Duke Energy Ohio/Kentucky (DEOK) region joined the PJM footprint. This report covers calendar year 2011, so Figure 1-1 and the data in this report do not include results from the DEOK area.

market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[6,7]

On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this 2011 State of the Market Report for PJM include the integration of the ATSI zone for the period from June through December.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2011, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

For each PJM market, market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referenced as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market performance, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

6 See also the *2011 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 Analysis of 2011 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2011, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

The MMU concludes the following for 2011:

Table 1-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9]

8 OATT Attachment M

Table 1-2 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.[10]
- 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.[11]
- 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

9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

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

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EM163 passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in M163 passed the TPS test.

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.

Table 1-3 The Regulation Market results were not competitive[12]

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 82 percent of the hours in 2011.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[13]

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 1-4 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 63 percent of the hours in 2011.

- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

12 As Table 1-3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

13 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 13 percent of offers reflected economic withholding, with offer prices above $5.00.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior in 2011.
- Performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[14] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[15]

Reporting

The MMU performs its reporting function by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

14 18 CFR § 35.28(g)(3)(ii); *see also Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

15 OATT Attachment M § IV; 18 CFR § 1c.2.

The MMU's reports on market issues cover specific topics in depth. For example, the MMU issues reports on RPM auctions. In addition, the MMU's reports frequently respond to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[16] The MMU has direct, confidential access to the FERC.[17] The MMU may also refer matters to the attention of State commissions.[18]

The MMU monitors market behavior for violations of FERC Market Rules.[19] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation,[20] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[23] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral[24] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[25] If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through ex ante mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[26] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[27]

The MMU also reviews operational parameter limits included with unit offers,[28] evaluates compliance with the requirement to offer into the energy and capacity markets,[29] evaluates the economic basis for unit retirement requests,[30] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[31]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or

16 OATT Attachment M § IV.
17 OATT Attachment M § IV.K.3.
18 OATT Attachment M § IV.H.
19 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.").
20 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
21 OATT Attachment M § II(h-1).
22 OATT Attachment M § IV.C.
23 OATT Attachment M § IV.I.1.
24 *Id.*

25 *Id.*
26 See OATT Attachment M–Appendix § II.A.
27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.
32 OATT Attachment M § IV.D.

regulatory proceedings.[33] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[34] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[37] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

Section 2, Energy Market

- There are no recommendations in Section 2.

Section 3, Operating Reserve

- The MMU recommends improving the process of identifying and classifying the reasons for paying operating reserve credits to both generation and demand side resources in order to ensure that market transactions pay only appropriate operating reserve charges.
- The MMU recommends that up-to congestion transactions pay balancing operating reserve charges.

Section 4, Capacity

- 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 obligations of capacity resources be more clearly defined in the market rules.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.
- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

Section 5, Demand Response

- The MMU recommends elimination of the Limited and Extended Summer Demand Response products from the capacity market. All products competing in the capacity market should be required to be available to perform when called for every hour of the year.
- The MMU recommends that PJM continue to implement subzonal dispatch for Demand Response products and develop a plan to implement nodal dispatch for all demand resources.
- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.
- The MMU recommends that there be improvement in measurement and verification methods implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. PJM has implemented or plans to implement changes to the CBL calculation that should improve measurement and verification for many customers.

33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.
37 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

Section 6, Net Revenue

- There are no recommendations in Section 6.

Section 7, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market.

Section 8, Interchange Transactions

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.
    - — The MMU recommends performing a regular assessment of the mappings of external balancing authorities associated with the interface pricing points, and modify as necessary to ensure that prices reflect the actual flows on the transmission system.
    - — The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.
    - — The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions).
        - On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[38] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
    - — The MMU recommends eliminating internal source and sink bus designations for external energy transactions in the Day-Ahead and Real-Time Energy Markets.
        - On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[39] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
    - — The MMU recommends eliminating or modifying the dispatchable transaction product to reduce the amount of balancing operating reserve credits associated with the uneconomic scheduling of the product.
        - On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into PJM's dispatch tool.[40] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.
    - — The MMU recommends eliminating or modifying the up-to congestion transaction product to ensure that it pays appropriate operating reserve charges and has appropriate credit requirements.
        - At the PJM Market Implementation Committee, held on February 17, 2012, the PJM stakeholders agreed to form a task force to address up-to congestion issues.
    - — The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as

38 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://112.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

39 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://112.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>. (May 16, 2011)

40 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://112.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx>. (July 13, 2011)

soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced.[41]

- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.
  - On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.[42] On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.[43] As of December 31, 2011, the Commission had not made a final decision.
- The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed, and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.
  - In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report is expected to be completed and distributed early in the first quarter of 2012.

Section 9, Ancillary Services

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. The MMU is hopeful that the opportunity cost issue can be resolved in 2012.
  - PJM will propose a redesign of the Regulation Market in 2011 to address fast response resources and other design issues.
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This is consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronize reserve deselection process be published.
- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test and cost-based offer caps in order to address potential market power issues.
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process.
- The MMU recommends that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs.
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market.

41 See "PJM Manual 41: Managing Interchange," Revision 03 (November 24, 2008), External Transaction Minimum Duration Requirement.

42 See 135 FERC ¶ 61,052 (2011).

43 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

Section 10, Congestion and Marginal Losses

- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results.

Section 11, Planning

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty and improve the efficiency of the process so as to eliminate any inappropriate barriers to the entry of new generation.
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.
- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

Section 12, Financial Transmission Rights and Auction Revenue Rights.

- The MMU recommends that a detailed review of the ARR/FTR allocation and market clearing be conducted in order to better understand and address the reasons for FTR underfunding. This review should include the assumptions made in the modeling of auctions and their basis in market developments. The MMU also recommends an explicit statement in the rules explaining the purpose and objectives of ARRs, FTRs and the appropriate level of funding of FTRs. The MMU recommends that no action to substantially modify the market design, e.g. removal of balancing congestion from the calculation of FTR revenues, be taken until the review is complete.
- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs, derived from the ARR allocation to that load, follow the load in the same manner as ARRs.

Highlights

The following presents highlights of each of the sections of the *2011 State of the Market Report for PJM*:

Section 2, Energy Market

- Average offered supply increased by 14,478, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011. The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011. (See page 23)
- In 2011, coal units provided 46.9 percent, nuclear units 34.2 percent and gas units 14.4 percent of total generation. Compared to calendar year 2010, generation from coal units decreased 0.8 percent, generation from nuclear units increased 3.3 percent, while generation from natural gas units increased 18.1 percent, and generation from oil units decreased 35.5 percent. (See page 23)
- Five large plants (over 500 MW) began generating in PJM in 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI integration), the most since 2002. (See page 286)
- The PJM system peak load for the summer of 2011 was 158,016 MW, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the summer of 2010.[44] The ATSI transmission zone accounted for 13,953 MW in the peak hour of summer 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, an increase of 7,603 MW from the 2010 peak load. (See page 24)
- PJM average real-time load in 2011 increased by 3.7 percent from 2010, from 79,611 MW to 82,541 MW. The PJM average real-time load in 2011 would have decreased by 2.0 percent from 2010, from 79,611

44 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

MW to 78,000 MW, if the ATSI transmission zone were excluded. (See page 38)

- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in 2011 by 9.6 percent from 2010, from 103,935 MW to 113,866 MW. PJM average day-ahead load would have been 0.2 percent higher in 2011 than in 2010, from 103,935 MW to 103,746 MW if the ATSI transmission zone were excluded. (See page 40)
- PJM average real-time generation increased by 3.9 percent in 2011 from 2010, from 82,582 MW to 85,775 MW. PJM average real-time generation would have decreased 1.4 percent in 2011 from 2010, from 82,582 MW to 81,645 MW if the ATSI transmission zone were excluded. (See page 42)
- PJM Real-Time Energy Market prices decreased in 2011 compared to 2010. The load-weighted average LMP was 5.0 percent lower in 2011 than in 2010, $45.94 per MWh versus $48.35 per MWh. (See page 45)
- PJM Day-Ahead Energy Market prices decreased in 2011 compared to 2010. The load-weighted average LMP was 5.2 percent lower in 2011 than in 2010, $45.19 per MWh versus $47.65 per MWh. (See page 48)
- Levels of offer capping for local market power remained low. In 2011, 0.9 percent of unit hours and 0.4 percent of MW were offer capped in the Real-Time Energy Market and 0.0 percent of unit hours and 0.0 percent of MW were offer capped in the Day-Ahead Energy Market. (See page 27)
- Of the 188 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during 2011, 54 (28.7 percent) qualified in all months, and 11 (5.9 percent) qualified in only one month of 2011. (See page 35)
- There were no scarcity pricing events in 2011 under PJM's current Emergency Action based scarcity pricing rules. (See page 56)

Section 3, Operating Reserve

- Operating reserve charges increased $5.8 million, or 1.0 percent, from $572.3 million in 2010, to $578.1 million in 2011. Balancing operating reserve charges (without lost opportunity cost charges) decreased by $49.4 million or 13.5 percent while lost opportunity cost charges increased by $58.5 million or 51.5 percent in 2011. (See page 67)
- Generators and real-time transactions balancing operating reserve charges were $288.8 million, 58.9 percent of all balancing operating reserve charges. Total balancing operating reserve charges were allocated 31.4 percent as reliability charges and 68.6 percent as deviation charges. Lost opportunity cost charges were $172.2 million or 35.2 percent of all balancing charges. The remaining 5.9 percent of balancing operating reserve charges were comprised of 1.8 percent canceled resources charges and 4.1 percent charges paid to resources controlling local transmission constraints. (See page 68)
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 28.1 percent of total operating reserve credits in 2011, compared to 33.2 percent in 2010. In 2011, the top generation owner received 21.0 percent of the total operating reserve credits paid. (See page 75)
- The regional concentration of balancing operating reserves remained high in 2011, although slightly lower than 2010. In 2011, 59.3 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 4.2 percent from the 2010 share. (See page 81)

Section 4, Capacity

- In calendar year 2011, PJM installed capacity increased 14,826.8 MW or 8.9 percent from 166,410.0 MW on January 1 to 178,846.5 MW on December 31, primarily due to the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM. Installed capacity includes net capacity imports and exports and can vary on a daily basis. (See page 91)
- The 2011/2012 RPM Third Incremental Auction, 2014/2015 RPM Base Residual Auction, 2012/2013 RPM Second Incremental Auction, and the 2013/2014 First Incremental Auction were run in calendar year 2011. In the 2011/2012 RPM Third Incremental Auction, the RTO clearing price was $5.00 per MW-day. In the 2014/2015 RPM Base

Residual Auction, the RTO clearing price for Limited Resources was $125.47 per MW-day, and the RTO clearing price for Extended Summer and Annual Resources was $125.99 per MW-day. In the 2012/2013 RPM Second Incremental Auction, the RTO resource clearing price was $13.01 per MW-day, and the EM163 resource clearing price was $48.91 per MW-day. In the 2013/2014 RPM First Incremental Auction, the RTO resource clearing price was $20.00 per MW-day, the EM163 resource clearing price was $178.85 per MW-day, and the SWM163 resource clearing price was $54.82 per MW-day. (See page 109)

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 Delivery Year. (See page 95)
- Capacity in the RPM load management programs was 9,688.3 MW for June 1, 2011. (See page 100)
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $127.05 per MW-day in 2014. (See page 109)
- Average PJM equivalent demand forced outage rate (EFORd) increased from 7.2 percent in 2010 to 7.9 percent in 2011. (See page 112)
- The PJM aggregate equivalent availability factor (EAF) decreased from 84.9 percent in 2010 to 83.7 percent in 2011. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2010 to 3.1 percent in 2011, the equivalent planned outage factor (EPOF) increased from 7.4 percent in 2010 to 7.9 percent in 2011, and the equivalent forced outage factor (EFOF) increased from 4.9 percent in 2010 to 5.3 percent in 2011. (See page 112)

Section 5, Demand Response

- In 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 57,288 MWh compared to the same period in 2010, from 74,070 MWh in 2010 to 16,782 MWh in 2011, a 77 percent decrease. Total payments under the Economic Program decreased by $1,080,438, from $3,088,049 in 2010 to $2,007,612 in 2011, a 35 percent decrease. (See page 131)
- In calendar year 2011, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by $25.2 million, or 4.9 percent, compared to the same period in 2010, from $512 million in 2010 to $487 million in 2011. (See page 133)

Section 6, Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP. (See page 147)
- The MMU estimates that there are 5,764 MW of RPM coal capacity at risk of retirement. Capacity at risk of retirement includes units that did not cover their avoidable costs in 2011 or would not be able to cover the cost of installing MATS compliant environmental controls, excludes units that have started the deactivation process or are expected to request deactivation, and excludes FRR capacity. (See page 157)

Section 7, Environmental and Renewables

- The EPA issued the Mercury Air Toxics Rule December 16, 2011, which will require significant investments in control technology for Mercury and other pollutants, effective April 16, 2015. (See page 163)
- Generation from wind units increased from 9,688.2 GWh in 2010 to 11,561.1 GWh in 2011, an increase of 19.3 percent. Generation from solar units increased from 5.7 GWh in 2010 to 55.7 GWh in 2011, an increase of 872.5 percent. (See page 173)

- At the end of 2011, the Cross-State Air Pollution Rule was subject to a stay pending further action on appeal, resulting in the reinstatement of the Clean Air Interstate Rule for 2012. (See page 161)
- Emission prices declined in calendar year 2011 compared to calendar year 2010. NO_x prices declined 64.3 percent in 2011 compared to 2010, and SO_2 prices declined 87.3 percent in 2011 compared to 2010. RGGI CO2 prices declined by 4.6 percent in 2011 compared to 2010. (See page 169)
- The price of RGGI CO_2 allowances remained at or near the floor price of $1.89 during 2011, and as of January 1, 2012, the state of New Jersey will no longer be participating in the RGGI program. (See page 168)

Section 8, Interchange Transactions

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated. (See page 196)
- Real-time net exports increased to -9,761.8 GWh in 2011 from -9,661.0 GWh for the calendar year 2010. Day-ahead net imports in 2011 were 6,576.2 GWh compared to net exports of -6,470.0 GWh for the calendar year 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. (See page 187)
- The direction of power flows was not consistent with real-time energy market price differences in 55 percent of hours at the border between PJM and MISO and in 48 percent of hours at the border between PJM and NYISO in 2011. (See page 198)
- In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh or 7.1 percent, an increase from 5.2 percent for the calendar year 2010. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. (See page 208)
- PJM initiated 62 TLRs in 2011, a reduction from the 110 TLRs for the calendar year 2010. (See page 211)
- The average daily volume of up-to congestion bids increased from 4,293 bids per day, for the period between March 1, 2009 through May 14, 2010, to 6,881 bids per day for the period between May 15, 2010 through September 16, 2010, to 26,303 bids per day for the period between September 17, 2010 and December 31, 2011. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.[45] (See page 212)
- Total uncollected congestion charges in 2011 were -$20,955, compared to $3.3 million for the calendar year 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case for the net uncollected congestion charges in 2011. (See page 218)
- Balancing operating reserve credits are paid to importing dispatchable transactions (also known as real-time with price) as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were $1.3 million, a decrease from $23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011. (See page 221)

Section 9, Ancillary Services

- The weighted average Regulation Market clearing price, including opportunity cost, for 2011 was

45 In prior state of the market reports for PJM, the number of up-to congestion bids reported represented unique up-to congestion transaction IDs. The new totals represent the total hours of up-to congestion bids per day. For example, if a unique up-to congestion transaction ID was submitted for all 24 hours of the day, it was counted as one bid in previous reports, and now is counted as 24 bids. This is consistent with the reporting of increment offers and decrement bids.

$16.21 per MW.[46] This was a decrease of $1.87, or 10 percent, from the average price for regulation in 2010. The total cost of regulation decreased by $2.79 from $32.07 per MW in 2010, to $29.28, or 8.7 percent. In 2011 the weighted Regulation Market clearing price was only 55 percent of the total regulation cost per MW, compared to 56 percent of the total costs of regulation per MW in 2010. (See page 236)

- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $11.81 per MW in 2011, a $1.26 per MW increase from 2010.[47] The total cost of synchronized reserves per MWh in 2011 was $15.48, a 7.4 percent increase from the total cost of synchronized reserves ($14.41) during 2010. The weighted average Synchronized Reserve Market clearing price was 76 percent of the weighted average total cost per MW of synchronized reserve in 2011, up from 73 percent in 2010. (See page 251)
- The weighted DASR market clearing price in 2011 was $0.55 per MW. In 2010, the weighted price of DASR was $0.16 per MW. The year over year increase in the weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. (See page 256)
- Black start zonal charges 2011 ranged from $0.04 per MW in the DLCO zone to $0.90 per MW in the BGE zone (See page 257)

Section 10, Congestion and Marginal Losses

- Total marginal loss costs in 2011 decreased by 15.6 percent from 2010 (Table 10-10). (See page 271)
- Net day-ahead marginal loss costs were $1,430.5 million in 2011 and net balancing marginal loss costs were -$51.0 million in 2011 (Table 10-12). (See page 272)
- American Electric Power (AEP) was the control zone with the most marginal loss costs in 2011. AEP accounted for $318.6 million or 23.1 percent of the $1,379.5 million total marginal loss costs. (See page 413)
- Monthly marginal loss costs in 2011 were lower than monthly marginal loss costs in 2010, with the exception of March and April (Table 10-12).[48] (See page 272)
- The marginal loss credits (loss surplus) decreased in 2011 to $586.7 million compared to $836.7 million in 2010. (Table 10-13). (See page 273)
- Congestion costs in 2011 decreased by 29.9 percent over congestion costs in 2010 (Table 10-17). (See page 275)
- Net day-ahead congestion costs were $1,244.9 million in 2011 and $1,713.1 in 2010. Net balancing congestion costs were -$246.7 million in 2011 (Table 10-18) and -$289.5 million in 2010. (See page 276)
- Monthly congestion costs in 2011 were lower than monthly congestion costs in 2010, with the exception of January and March (Table 10-19 and Table 10-20). (See page 277)

Section 11, Planning

- At December 31, 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 including the June 1, 2011, ATSI integration. Wind projects account for approximately 37,792 MW, 41.7 percent of the capacity in the queues, and combined-cycle projects account for 34,138 MW, 37.6 percent of the capacity in the queues. (See page 286)
- Five large plants (over 500 MW) began generating in PJM in 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone.[49] This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002. (See page 286)
- A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will have retired from 2011 through 2019, with most

46 The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

47 The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

48 See the *2010 State of the Market Report for PJM*, Volume II, "Energy Market, Part 1," Table 2-58.

49 Fremont Energy Center entered PJM after the June 1, 2011 integration of ATSI, and is included in the 5,008 MW of nameplate capacity reported above.

of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. (See page 291)

Section 12, Financial Transmission Rights and Auction Revenue Rights

- On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period. (See page 305)
- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 planning period increased by 47 percent from 1,092,956 MW to 1,589,989 MW compared to the first seven months of the 2010 to 2011 planning period. (See page 312)
- FTRs were paid at 85.0 percent of the target allocation level for the full 2010 to 2011 planning period and 84.9 percent for the first seven months of the 2011 to 2012 planning period. (See page 329)
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were profitable overall and were profitable for both physical and financial entities in the 2011 calendar year. Total FTR profits were $340.3 million for physical entities and $125.7 million for financial entities. Self scheduled FTRs were the source of $560.5 million of the FTR profits for physical entities. Not every FTR was profitable. FTRs purchased by physical entities, but not self scheduled, were not profitable in 2011. (See page 333)
- As one of the measures to address underfunding, effective August 5, 2011, PJM no longer allows FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. (See page 320)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-7 provides the average price and total revenues paid, by component for 2010 and 2011.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 96.0 percent of the total price per MWh in 2011. The cost of energy was 73.4 percent, the cost of capacity was 15.5 percent and the cost of transmission service was 7.1 percent of the total price per MWh in 2011.

The total price per MWh of wholesale power in 2011, $62.56, was 6.2 percent lower than total per MWh price of wholesale power in 2010, $66.72. This decrease in the total price per MWh was largely attributable to the 5.0 percent decrease in the average energy price per MWh and the 20.0 percent decrease in the average price of capacity per MWh between 2010 and 2011.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[50]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[51]

50 OATT §§ 13.7, 14.5, 27A & 34.
51 OA Schedules 1 §§ 3.2.3 & 3.3.3.

Table 1-7 Total price per MWh by category and total revenues by category: 2010 and 2011

Category	2010 $/MWh	2011 $/MWh	Percent Change Totals	2010 Percent of Total	2011 Percent of Total
Energy	$48.35	$45.94	(5.0%)	72.5%	73.4%
Capacity	$12.15	$9.72	(20.0%)	18.2%	15.5%
Transmission Service Charges	$4.00	$4.42	10.5%	6.0%	7.1%
Operating Reserves (Uplift)	$0.79	$0.79	1.1%	1.2%	1.3%
Reactive	$0.44	$0.42	(6.6%)	0.7%	0.7%
PJM Administrative Fees	$0.36	$0.37	3.4%	0.5%	0.6%
Regulation	$0.35	$0.32	(6.6%)	0.5%	0.5%
Transmission Enhancement Cost Recovery	$0.21	$0.29	39.0%	0.3%	0.5%
Synchronized Reserves	$0.06	$0.09	47.4%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	$0.09	$0.09	1.5%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.05	391.9%	0.0%	0.1%
Black Start	$0.02	$0.02	22.4%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(7.6%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.9%)	0.0%	0.0%
Load Response	$0.00	$0.01	28.6%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	19.1%	0.0%	0.0%
Total	$66.72	$62.56	(6.2%)	100.0%	100.0%

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[52]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[53]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[54]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[55]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[56]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[57]
- The Black Start component is the average cost per MWh of black start service.[58]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[59]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[60]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[61]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[62]

Table 1-8 provides the average price by component for calendar years 2000 through 2011.

Table 1-8 shows that from 2007 through 2011 Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh

52 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
53 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
54 OATT Schedule 12.
55 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
56 OATT Schedule 1A.
57 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
58 OATT Schedule 6A. The Black Start charges do not include Operating Reserve charges required for units to provide Black Start Service under the ALR option.
59 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
60 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
61 OA Schedule 1 § 3.6.
62 OA Schedule 1 § 5.3b.

of wholesale power, comprising more than 96.0 percent of the total price per MWh each year. Over the 2000 to 2011 period these three components were a minimum of 94.7 percent of the total price per MWh each year. Of these components, the cost of energy was consistently the most important, making up from 69.9 to 91.1 percent of the total price per MWh for the 2000 through 2011 period. The cost of capacity varied between 0.04 percent and 19.73 percent over the same period due to the introduction of a new capacity market design in 2007. Transmission Service Charges contributed from 3.9 to 9.1 percent of the total price per MWh on an annual basis for the 2000 through 2011 period.

Table 1-8 Total price per MWh by category: Calendar Years 2000 through 2011[1]

Category	Totals ($/MWh) 2000	Totals ($/MWh) 2001	Totals ($/MWh) 2002	Totals ($/MWh) 2003	Totals ($/MWh) 2004	Totals ($/MWh) 2005	Totals ($/MWh) 2006	Totals ($/MWh) 2007	Totals ($/MWh) 2008	Totals ($/MWh) 2009	Totals ($/MWh) 2010	Totals ($/MWh) 2011
Energy	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94
Capacity	$0.20	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.15	$9.72
Transmission Service Charges	$2.17	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00	$4.42
Operating Reserves (Uplift)	$0.57	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79	$0.79
Reactive	$0.15	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44	$0.42
PJM Administrative Fees	$0.15	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36	$0.37
Regulation	$0.30	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35	$0.32
Transmission Enhancement Cost Recovery										$0.09	$0.21	$0.29
Synchronized Reserves			$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06	$0.09
Transmssion Owner (Schedule 1A)	$0.05	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09	$0.09
Day Ahead Scheduling Reserve (DASR)									$0.00	$0.00	$0.01	$0.05
Black Start			$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
NERC/RFC								$0.01	$0.01	$0.01	$0.02	$0.02
RTO Startup and Expansion			$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01	$0.01
Load Response	$0.00	-$0.00	$0.00	$0.02	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00	$0.01
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$34.32	$42.66	$37.05	$47.36	$50.25	$69.20	$58.58	$71.30	$85.24	$55.85	$66.72	$62.56

Table 1-9 Percentage of total price per MWh by category: Calendar years 2000 through 2011[2]

Category	Percentage of Total Charges 2000	Percentage of Total Charges 2001	Percentage of Total Charges 2002	Percentage of Total Charges 2003	Percentage of Total Charges 2004	Percentage of Total Charges 2005	Percentage of Total Charges 2006	Percentage of Total Charges 2007	Percentage of Total Charges 2008	Percentage of Total Charges 2009	Percentage of Total Charges 2010	Percentage of Total Charges 2011
Energy	89.5%	85.9%	85.3%	87.1%	88.2%	91.7%	91.1%	86.5%	83.4%	69.9%	72.5%	73.4%
Capacity	0.6%	0.7%	0.3%	0.2%	0.2%	0.0%	0.0%	5.6%	9.8%	19.7%	18.2%	15.5%
Transmission Service Charges	6.3%	8.1%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%
Operating Reserves (Uplift)	1.7%	2.5%	1.9%	1.8%	1.8%	1.4%	0.8%	0.9%	0.7%	0.9%	1.2%	1.3%
Reactive	0.4%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%
PJM Administrative Fees	0.4%	0.8%	1.2%	1.1%	1.0%	0.5%	0.7%	0.5%	0.3%	0.5%	0.5%	0.6%
Regulation	0.9%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%
Transmission Enhancement Cost Recovery										0.2%	0.3%	0.5%
Synchronized Reserves			0.3%	0.4%	0.3%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	0.1%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)									0.0%	0.0%	0.0%	0.1%
Black Start			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NERC/RFC								0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion			0.1%	0.1%	0.2%	0.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1 Data are missing for January through May of 2000 and January of 2002.
2 Data are missing for January through May of 2000 and January of 2002.

Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for 2011, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2011.

Table 2-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Overview

Market Structure

- **Supply.** Average offered supply increased by 14,478 MW, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011.[4] The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. This includes five large plants (over 500 MW) that began generating in PJM in 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011.
- **Demand.** The PJM system peak load for the summer of 2011 was 158,016 MW in the HE 1700 on July 21,

1 Analysis of 2011 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 OATT Attachment M

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 Calculated values shown in Section 2, "Energy Market" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the summer of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[5] The ATSI transmission zone accounted for 13,953 MW in the peak hour of summer 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2011. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours decreased from 0.2 percent in 2010 to 0.0 percent in 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.9 percent in 2011.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 188 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer in 2011, 54 (28.7 percent) qualified in all months, and 11 (5.9 percent) qualified in only one month of 2011.

- **Local Market Structure.** In 2011, ten Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[6]

Market Performance: Load, Generation and Locational Marginal Price

- **Load.** PJM average real-time load in 2011 increased by 3.7 percent from 2010, from 79,611 MW to 82,541 MW. The PJM average real-time load in 2011 would have decreased by 2.0 percent from 2010, from 79,611 MW to 78,000 MW, if the ATSI transmission zone were excluded.

  PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, increased by 6.2 percent from 2010, from 103,935 MW to 113,866 MW. PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, would have been 0.2 percent lower than in 2010, from 103,935 MW to 103,746 MW if the ATSI transmission zone were excluded.

- **Generation.** PJM average real-time generation in 2011 increased by 3.9 percent from 2010, from 82,582 MW to 85,775 MW. PJM average real-time generation in 2011 would have decreased 1.4 percent from 2010, from 82,582 MW to 81,645 MW if the ATSI transmission zone were excluded.

  PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, increased by 9.2 percent from 2010, from 107,290 MW to 117,130 MW. PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, would have been 4.8 percent higher than in 2010, from 107,290 MW to 112,424 MW if the ATSI transmission zone were excluded.

- **Generation Fuel Mix.** During 2011, coal units provided 46.9 percent, nuclear units 34.2 percent and gas units 14.4 percent of total generation. Compared to 2010, generation from coal units decreased 0.8 percent, generation from nuclear units increased 3.3 percent, generation from natural gas units increased 18.2 percent, and generation from oil units decreased 35.5 percent.

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

6 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.4 percent lower in 2011 than in 2010, $42.84 per MWh versus $44.83 per MWh. The load-weighted average LMP was 5.0 percent lower in 2011 than in 2010, $45.94 per MWh versus $48.35 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.6 percent lower in 2011 than in 2010, $42.52 per MWh versus $44.57 per MWh. The load-weighted average LMP was 5.2 percent lower in 2011 than in 2010, $45.19 per MWh versus $47.65 per MWh.[7]

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 26.6 percent by spot market purchases and 62.9 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 6.4 percentage points; and reliance on self-supply decreased by 5.1 percentage points in 2011. In 2011, 5.8 percent of day-ahead load was supplied by bilateral contracts, 24.4 percent by spot market purchases and 69.8 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.9 percentage points; reliance on spot supply increased by 5.1 percentage points; and reliance on self-supply decreased by 6.1 percentage points in 2011.

7 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market".

Scarcity

- **Scarcity Pricing Events in 2011.** PJM did not declare a scarcity event in 2011.
- **Scarcity and High Load Analyses.** There were no reserve shortage events in 2011. There were a total of 35 high-load hours in 2011. There were 22 Hot Weather Alerts called within the PJM footprint in 2011.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2011, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices in this section of the report.

Aggregate hourly supply offered increased by about 14,478 MWh in the summer of 2011 compared to the summer of 2010, while aggregate peak load increased by 21,556 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time Market, average load in 2011 increased from 2010, from 79,611 MW to 82,541 MW. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for 2011 generally reflected supply-demand fundamentals.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.[8]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

The MMU concludes that the PJM Energy Market results were competitive in 2011.

Market Structure

Supply

During the June to September 2011 summer period, the PJM Energy Market received a daily average of 170,481 MW in total supply offers including hydroelectric generation. The summer 2011 average daily offered supply was 14,478 MW higher than the summer 2010 average daily offered supply of 156,003 MW. Supply was affected by the integration of ATSI.

During the summer of 2011, the peak demand was 21,556 MW higher, 15.8 percent, than the 2010 peak, which, when combined with a shift to the right of the 2011 supply curve, resulted in a higher price level for peak demand (Figure 2-1). The smaller increase in average summer load resulted in approximately the same price level. Demand was affected by the integration of ATSI.

Some fuel types experienced price increases for the summer months in 2011 compared to the summer months in 2010, including a 16.3 percent increase in

8 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

coal prices, and a 48.8 percent increase in oil prices.[9] Natural gas prices in the PJM region decreased by 6.1 percent in the summer months of 2011 compared to the summer months of 2010. The result was somewhat lower prices in the summer months of 2011 than in 2010.

Figure 2-1 Average PJM aggregate supply curves: Summer 2010 and 2011

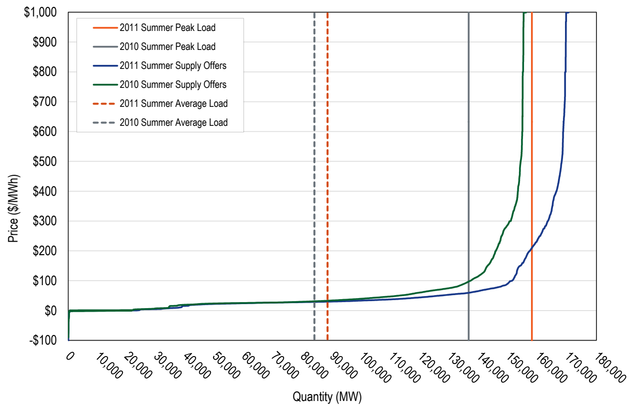


Table 2-2 PJM generation (By fuel source (GWh)): Calendar years 2010 and 2011[10]

	2010		2011		Change in
	GWh	Percent	GWh	Percent	Output
Coal	363,035.1	48.7%	360,306.2	46.9%	(0.8%)
Standard Coal	350,539.2	47.0%	348,100.5	45.3%	(0.7%)
Waste Coal	12,495.9	1.7%	12,205.7	1.6%	(0.1%)
Nuclear	254,534.1	34.2%	262,968.3	34.2%	3.3%
Gas	93,455.9	12.5%	110,345.3	14.4%	18.1%
Natural Gas	91,729.4	12.3%	108,456.7	14.1%	18.2%
Landfill Gas	1,726.0	0.2%	1,887.9	0.2%	9.4%
Biomass Gas	0.5	0.0%	0.6	0.0%	39.4%
Hydroelectric	14,384.4	1.9%	15,277.9	2.0%	6.2%
Wind	9,688.2	1.3%	11,561.1	1.5%	19.3%
Waste	6,731.5	0.9%	5,559.6	0.7%	(17.4%)
Solid Waste	5,033.9	0.7%	4,442.9	0.6%	(11.7%)
Miscellaneous	1,697.7	0.2%	1,116.6	0.1%	(34.2%)
Oil	3,313.3	0.4%	2,136.0	0.3%	(35.5%)
Heavy Oil	2,748.3	0.4%	1,749.8	0.2%	(36.3%)
Light Oil	508.8	0.1%	356.6	0.0%	(29.9%)
Diesel	32.3	0.0%	16.9	0.0%	(47.9%)
Kerosene	23.8	0.0%	12.8	0.0%	(46.4%)
Jet Oil	0.1	0.0%	0.1	0.0%	1.0%
Solar	5.7	0.0%	55.7	0.0%	872.5%
Battery	0.3	0.0%	0.2	0.0%	(24.8%)
Total	745,148.6	100.0%	768,210.2	100.0%	3.1%

Energy Production by Fuel Source

In 2011, coal units provided 46.9 percent, nuclear units 34.2 percent, gas 14.4 percent, oil 0.3 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.5 percent of total generation (Table 2-2). Compared to calendar year 2010, generation from coal units decreased 0.8 percent and generation from oil units decreased 35.5 percent. Generation from natural gas units increased 18.2 percent and generation from nuclear units increased 3.3 percent. Although starting from a relatively small base, generation from wind increased 19.3 percent and generation from solar increased 872.5 percent.

Generator Offers

Table 2-3 shows the distribution of MW generator offers by offer prices for 2011. For example, daily generator offer prices between $0 and $200 in 2011 accounted for 57.1 percent of all daily MW generator offers in 2011. Of the 57.1 percent of daily MW generators offered at prices between $0 and $200, 70.9 percent were dispatchable by PJM, 40.5 percent of all offered MW, while the other 29.1 percent were self-scheduled, 16.6 percent of all offered MW. Daily generator offer prices above $800 in 2011 accounted for 0.7 percent of all daily generator offers, of which 89.9 percent were economically dispatchable, and the other 10.1 percent self-scheduled.

9 Natural gas, light oil, and coal prices are the average of daily fuel price indices in the PJM footprint. All fuel prices are from Platts.

10 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

Table 2-3 Distribution[11] of MW for unit offer prices: Calendar year 2011

	Range												
	($200) - $0		$0 - $200		$200 - $400		$400 - $600		$600 - $800		$800 - $1,000		
Unit Type	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Total
Battery	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	97.9%	0.0%	100.0%
CC	0.0%	0.1%	65.5%	11.3%	14.6%	0.3%	3.0%	0.1%	3.8%	0.4%	0.9%	0.0%	100.0%
CT	0.0%	0.4%	41.6%	0.1%	16.1%	0.0%	11.8%	0.1%	27.4%	0.0%	2.3%	0.1%	100.0%
Diesel	0.0%	17.1%	11.3%	10.3%	51.8%	0.1%	6.5%	0.0%	1.8%	0.0%	1.0%	0.0%	100.0%
Hydro	0.1%	97.8%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	100.0%
Nuclear	0.0%	51.2%	11.7%	37.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Pumped Storage	57.5%	42.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Solar	0.3%	99.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Steam	0.0%	1.5%	48.6%	21.2%	20.6%	6.9%	0.8%	0.1%	0.0%	0.1%	0.1%	0.1%	100.0%
Transaction	0.0%	77.0%	0.0%	23.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	33.5%	65.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
All Offers (by type)	1.8%	13.2%	40.5%	16.6%	14.4%	3.1%	3.2%	0.1%	6.2%	0.1%	0.7%	0.1%	100.0%
All Offers (total)		15.0%		57.1%		17.5%		3.3%		6.3%		0.7%	100.0%

Table 2-4 Actual PJM footprint peak loads: 2002 to 2011

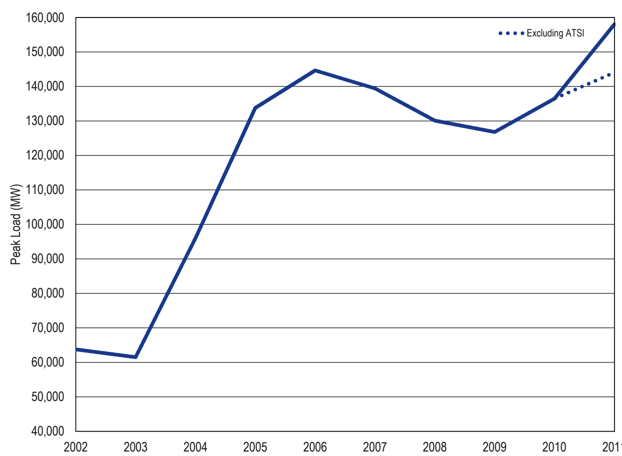
Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2002	Wed, August 14	16	63,762	NA	NA
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Mon, December 20	19	96,016	34,517	56.1%
2005	Tue, July 26	16	133,761	37,746	39.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011 (with ATSI)	Thu, July 21	17	158,016	21,556	15.8%
2011 (without ATSI)	Thu, July 21	17	144,063	7,603	5.6%

Demand

Table 2-4 shows the coincident summer peak loads for the years 2002 through 2011. The 2011 summer peak load of 158,016 MW was 21,556 MW more than the 2010 summer peak load of 136,465 MW and was the highest peak load since 2006, when peak load reached 144,644 MW. The 2011 summer peak load not including the ATSI zone was 144,063 MW. This peak load was 7,603 MW more than the 2010 summer peak load and was still the highest peak demand since 2006. This measure of peak load is the total amount of generation output and net energy imports required to meet the peak demand on the system, including losses, rather than the actual load served.[12]

Figure 2-2 shows the annual peak loads since 2002.

Figure 2-2 PJM[13] footprint annual peak loads: 2002 to 2011



The hourly load and average PJM LMP for the 2011 and 2010 summer peak days are shown in Figure 2-3. The peak for 2011 occurred on July 21, at hour ending 1700. The hourly integrated LMP for this hour was $162.28

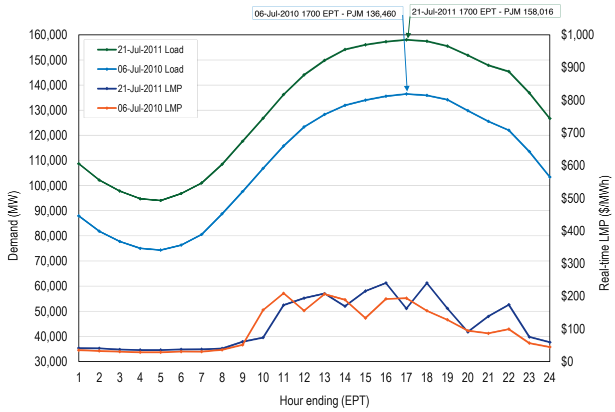
11 Each range in the table is greater than the start value and less than or equal to the end value.

12 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

13 For additional information on the "PJM Integration Period", see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

per MWh. The peak for 2010 occurred on July 6, at hour ending 1700. The hourly integrated LMP for this hour was $194.02 per MWh.

Figure 2-3 PJM annual peak-load comparison: Thursday, July 21, 2011, and Tuesday, July 06, 2010



Market Concentration

During 2011, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[14] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during 2011. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure.[15] The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-5).

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and

14 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

15 HHI and market share are commonly used, but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[16]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2011 was moderately concentrated (Table 2-5). In the Energy Market, average hourly HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011. The highest hourly market share was 30 percent and the average of the highest hourly market share for 2011 was 21 percent.

Table 2-5 PJM hourly Energy Market HHI: Calendar year 2011[17]

	Hourly Market HHI
Average	1203
Minimum	889
Maximum	1564
Highest market share (One hour)	30%
Average of the highest hourly market share	21%
# Hours	8,760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

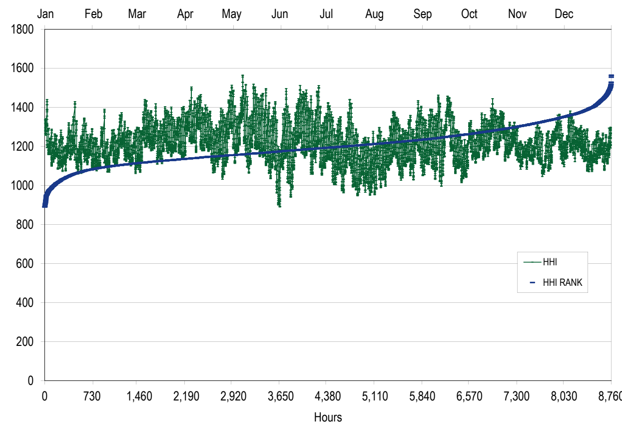
Table 2-6 includes 2011 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, the baseload segment of the supply curve is moderately concentrated, while the intermediate and peaking segments of the supply curve are highly concentrated.

Table 2-6 PJM hourly Energy Market HHI (By supply segment): Calendar year 2011

	Minimum	Average	Maximum
Base	1034	1224	1534
Intermediate	676	1831	7964
Peak	596	6034	10000

Figure 2-4 presents the 2011 hourly HHI values in chronological order and an HHI duration curve that shows 2011 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 1.6 percent of the hours while HHI values were in the moderately concentrated range in the remaining 98.4 percent of hours, with a maximum value of 1564, as shown in Table 2-5.

Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2011



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[18] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market

16 Order No. 592, *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement,"* 77 FERC ¶ 61,263, pp. 64-70 (1996)

17 This analysis includes all hours of 2011, regardless of congestion.

18 OA Schedule 1, Section 6.4.2.

power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[19]

Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[20] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-7.

Table 2-7 Annual offer-capping statistics: Calendar years 2007 through 2011

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%

Table 2-8 presents data on the frequency with which units were offer capped in 2011. Table 2-8 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2011. For example, in 2011, only nine units were offer-capped for greater than or equal to 80 percent of their run hours and had 200 or more offer-capped run hours.

Table 2-8 Real-time offer-capped unit statistics: Calendar Year 2011

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

Table 2-8 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 31 units (about 2.2 percent of all units) that had offer-capped run hours of at least 200 hours (about 2.3 percent of all hours) in 2011 were offer capped for 10 percent or more of their run hours. Only 14 units (or about one percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

The number of units that had at least 100 offer capped run hours and that were offer capped for 90 percent or more of their run hours increased from 3 in 2010 to 15 in 2011. The number of units that had at least 500 offer capped hours and that were offer capped for 50 percent or more of their run hours decreased from six in 2010 to 0 in 2011.[21]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

19 123 FERC ¶ 61,169 (2008).

20 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test."

21 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-23 for 2010 data.

Local Market Structure

In 2011, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, Met-Ed, PECO and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for calendar year 2011.[22] The DAY, DPL, JCPL, PENELEC, Pepco, PPL and RECO Control Zones were not affected by constraints binding for 100 or more hours.[23]

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.[24]

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2011, through December 31, 2011. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small. The results show that the percentage of tests where one or more suppliers pass the three pivotal supplier test increases as the number of suppliers increases and as the residual supply in the local market increases. The results also show that the percentage of tests where one or more suppliers fail the three pivotal supplier test increases as the number of suppliers decreases and the residual supply in the local market decreases.

Information is provided for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping, and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[25] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test. In 2011, eight regional 500 kV transmission constraints occurred for more than 100 hours. The Cloverdale – Lexington line, along with seven interface constraints (5004/5005, AEP – Dominion, Bedington — Black Oak, Dominion East[26], Eastern, Western and AP South) all experienced more than 100 hours of congestion.[27] Interfaces are groups of transmission facilities where reactive transfer limits are the basis for limits on the total flow across the transmission paths. Table 2-9 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table 2-9 shows that most of the tests resulted in one or more owners failing for the AEP – Dominion interface, AP South interface, the Cloverdale – Lexington line, and the Dominion East interface.

When compared to 2010 TPS results, the total number of tests applied for the 5004/5005 interface increased from 9,731 to 10,993, while the percentage of tests with one or more owners failing increased from 80 percent to 92 percent on peak and from 61 percent to 94 percent off peak. As shown in Table 2-11 the number of tests that resulted in offer capping for the 5004/5005 interface decreased from 387 in 2010 to 259 in 2011. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

22 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

23 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

24 The FERC eliminated the exemption of interfaces effective May 17, 2008. 123 FERC ¶ 61,169 (2008).

25 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

26 The Dominion East (DomEast) interface was temporarily created to monitor for voltage collapse in the Eastern Dominion area. See "Eastern Dominion Voltage Control" <http://www.pjm.com/~/media/etools/oasis/system-information/om66-temporary-domeast-interface-septa-fentress-op-guide.ashx> (Accessed February 20, 2012)

27 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

Table 2-9 Three pivotal supplier results summary for regional constraints: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	7,304	1,349	18%	6,686	92%
	Off Peak	3,689	511	14%	3,458	94%
AEP-DOM	Peak	1,853	28	2%	1,846	100%
	Off Peak	2,252	48	2%	2,238	99%
AP South	Peak	19,315	638	3%	19,086	99%
	Off Peak	14,439	548	4%	14,255	99%
Bedington - Black Oak	Peak	42	0	0%	42	100%
	Off Peak	9	1	11%	8	89%
Cloverdale - Lexington	Peak	2,453	271	11%	2,363	96%
	Off Peak	9,164	787	9%	8,975	98%
Dominion East	Peak	1,479	12	1%	1,469	99%
	Off Peak	578	8	1%	575	99%
Eastern	Peak	726	221	30%	636	88%
	Off Peak	155	63	41%	118	76%
Western	Peak	211	93	44%	158	75%
	Off Peak	21	10	48%	16	76%

Table 2-10 Three pivotal supplier test details for regional constraints: Calendar year 2011[28]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	304	372	15	2	13
	Off Peak	367	385	14	2	12
AEP-DOM	Peak	274	311	8	0	8
	Off Peak	337	410	8	0	8
AP South	Peak	368	436	8	0	8
	Off Peak	451	502	9	0	8
Bedington - Black Oak	Peak	71	74	8	0	8
	Off Peak	19	40	9	1	8
Cloverdale - Lexington	Peak	191	231	12	1	11
	Off Peak	198	266	11	1	10
Dominion East	Peak	115	164	1	0	1
	Off Peak	80	140	2	0	2
Eastern	Peak	637	898	16	5	11
	Off Peak	327	531	12	5	7
Western	Peak	434	615	14	6	8
	Off Peak	218	423	13	5	8

Table 2-10 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing for the regional 500 kV constraints.

The three pivotal supplier test is applied every time the system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 2-11 provides, for the identified eight regional constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units. Table 2-11 shows that only a small fraction of the tests applied to the regional 500 kV constraints resulted in offer capping. Of all the tests applied to the regional 500 kV constraints, no more than three percent of the tests for any constraint resulted in offer capping.

28 The version of this table in prior versions of the State of the Market Report incorrectly reported the Average Effective Supply.

Table 2-11 Summary of three pivotal supplier tests applied for regional constraints: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	7,304	397	5%	190	3%	48%
	Off Peak	3,689	184	5%	69	2%	38%
AEP-DOM	Peak	1,853	38	2%	14	1%	37%
	Off Peak	2,252	47	2%	26	1%	55%
AP South	Peak	19,315	219	1%	62	0%	28%
	Off Peak	14,439	233	2%	58	0%	25%
Bedington - Black Oak	Peak	42	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%
Cloverdale - Lexington	Peak	2,453	116	5%	53	2%	46%
	Off Peak	9,164	185	2%	47	1%	25%
Dominion East	Peak	1,479	6	0%	0	0%	0%
	Off Peak	578	0	0%	0	0%	0%
Eastern	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
Western	Peak	211	17	8%	7	3%	41%
	Off Peak	21	1	5%	0	0%	0%

Ownership of Marginal Resources

Table 2-12 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[29] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during 2011, the offers of one company contributed 12 percent of the real-time, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 36 percent of the real-time, annual, load-weighted, average PJM system LMP.

Table 2-12 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): Calendar year 2011

Company	Percent of Price
1	12%
2	9%
3	8%
4	7%
5	6%
6	6%
7	5%
8	5%
9	5%
Other (68 companies)	37%

Table 2-13 shows the contribution to PJM day-ahead, annual, load-weighted LMP by individual marginal resource owner.[30] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Day-Ahead Energy Market. The results show that, during 2011, the offers of one company contributed 11 percent of the day-ahead, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 34 percent of the day-ahead, annual, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2011

Company	Percent of Price
1	11%
2	8%
3	8%
4	7%
5	6%
6	4%
7	4%
8	4%
9	4%
Other (149 companies)	45%

29 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

30 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Market. INC offers, DEC bids and price sensitive transactions are dispatchable injections and withdrawals in the Day-Ahead market that can either directly or indirectly set price via their offers and bids. This section identifies the 2011 marginal resources by type for both Real-Time and Day-Ahead Markets.

Table 2-14 shows the type of fuel used by marginal resources in the Real Time Energy Market. In 2011, coal units were 69 percent of marginal resources and natural gas units were 26 percent of marginal resources.

Table 2-14 Type of fuel used (By real-time marginal units): Calendar year 2011

Fuel Type	2011
Coal	69%
Gas	26%
Wind	2%
Oil	2%
Municipal Waste	1%
Interface	0%
Uranium	0%

Table 2-15 shows the type of marginal resources in the Day-Ahead Energy Market. In 2011, up-to congestion transactions accounted for 73 percent of marginal resources and the decrement bids accounted for 12 percent of all marginal resources cleared in the Day-Ahead market.

Table 2-15 Day-ahead marginal resources by type/fuel: Calendar year 2011

Type/Fuel	2011
Up-to Congestion Transaction	73%
DEC	12%
INC	8%
Coal	5%
Gas	2%
Price Sensitive Demand	0%
Dispatchable Transaction	0%
Wind	0%
Oil	0%
Municipal Waste	0%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. This index calculation method weights the impact of individual unit markups using sensitivity factors, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-16 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-16 Average, real-time marginal unit markup index (By price category): Calendar year 2011

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($2.36)
$25 to $50	(0.04)	($1.73)
$50 to $75	0.01	$0.38
$75 to $100	0.14	$11.72
$100 to $125	0.25	$27.71
$125 to $150	0.25	$33.16
> $150	0.12	$23.29

Day-Ahead Mark Up Conduct

Table 2-17 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-17 Average marginal unit markup index (By price category): Calendar year 2011

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.07)	($2.10)
$25 to $50	(0.04)	($1.77)
$50 to $75	0.03	$1.86
$75 to $100	0.16	$12.62
$100 to $125	0.10	$11.62
$125 to $150	0.03	$4.73
> $150	0.22	$40.93

Market Performance

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[31]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by marginal units with price-based offers, and the system price, based on the cost-based offers of those marginal units.

Table 2-18 shows the annual average unit markup component of LMP for marginal units, by unit type and primary fuel.

Table 2-18 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2011

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.42)	(33.1%)
Gas	CC	$1.48	116.0%
Gas	CT	$0.15	11.3%
Gas	Diesel	$0.00	0.1%
Gas	Steam	$0.02	1.3%
Interface	Interface	$0.00	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.05	3.8%
Oil	CT	$0.01	0.5%
Oil	Diesel	$0.01	0.4%
Oil	Steam	($0.01)	(0.6%)
Uranium	Steam	($0.00)	(0.0%)
Wind	Wind	$0.00	0.3%
Total		$1.28	100.0%

Markup Component of Real-Time System Price

Table 2-19 shows the markup component of average prices and of average monthly on-peak and off-peak

31 This is the same method used to calculate the fuel-cost-adjusted LMP and the components of LMP.

prices. In 2011, $1.28 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2011, the markup component of LMP was -$0.62 per MWh off peak and $3.05 per MWh on peak.

Table 2-19 Monthly markup components of real-time load-weighted LMP: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.58	$1.84	$1.33
Feb	($0.19)	$0.26	($0.66)
Mar	$0.18	$1.59	($1.39)
Apr	$1.09	$2.86	($0.78)
May	$4.95	$9.55	$0.31
Jun	$2.20	$4.66	($0.84)
Jul	$4.19	$7.50	$1.03
Aug	$2.58	$5.60	($1.23)
Sep	($0.02)	$1.81	($1.75)
Oct	($1.10)	($0.58)	($1.62)
Nov	($0.81)	($0.30)	($1.35)
Dec	($0.66)	($0.10)	($1.14)
2011	$1.28	$3.05	($0.62)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-20. The smallest zonal all hours' annual average markup component was in the ATSI Control Zone, $0.28 per MWh, while the highest all hours' annual average zonal markup component was in the AECO Control Zone, $2.30 per MWh. On peak, the smallest annual average zonal markup was in the ATSI Control Zone, $1.86 per MWh, while the highest annual average zonal markup was in the AECO Control Zone, $4.73 per MWh. Off peak, the smallest annual average zonal markup was in the ATSI Control Zone, -$1.46 per MWh, while the highest annual average zonal markup was in the Dominion Control Zone, $0.12 per MWh.

Table 2-20 Average real-time zonal markup component: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.30	$4.73	($0.21)
AEP	$0.42	$1.92	($1.13)
AP	$0.97	$2.61	($0.75)
ATSI	$0.28	$1.86	($1.46)
BGE	$2.24	$4.45	($0.09)
ComEd	$1.03	$2.41	($0.47)
DAY	$0.48	$2.04	($1.23)
DLCO	$0.47	$2.15	($1.29)
Dominion	$1.97	$3.67	$0.12
DPL	$1.91	$3.94	($0.25)
JCPL	$2.05	$4.34	($0.53)
Met-Ed	$1.71	$3.78	($0.53)
PECO	$1.74	$3.86	($0.51)
PENELEC	$0.77	$2.53	($1.08)
Pepco	$1.95	$3.76	($0.06)
PPL	$1.69	$3.79	($0.58)
PSEG	$1.80	$4.04	($0.66)
RECO	$2.02	$3.85	($0.16)

Markup by Real-Time System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-21 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-21 Average real-time markup component (By price category): Calendar year 2011

	Average Markup Component	Frequency
< $25	($3.11)	5.6%
$25 to $50	($2.22)	77.2%
$50 to $75	$4.17	10.1%
$75 to $100	$17.04	3.6%
$100 to $125	$25.98	1.6%
$125 to $150	$33.51	0.9%
> $150	$54.60	1.1%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-22. The coal steam units accounted for 118.7 percent of the markup component of overall PJM day-ahead, load-weighted average LMP.

Table 2-22 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2011

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.09)	118.7%
Municipal Waste	Steam	($0.00)	0.1%
Gas	CT	$0.04	(3.8%)
Gas	Diesel	$0.00	0.0%
Gas	Steam	$0.14	(15.3%)
Oil	Steam	($0.00)	0.3%
Wind	Wind	$0.00	0.0%
Total		($0.92)	100.0%

Markup Component of Day-Ahead System Price

The markup component of day-ahead price is the difference between the day-ahead system price, when the day-ahead system price is determined by marginal units with price-based offers, and the day-ahead system price, based on the cost-based offers of those marginal units.

Table 2-23 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2011, the markup component of LMP was -$1.85 per MWh off peak and -$0.06 per MWh on peak.

Table 2-23 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.48)	$0.13	($1.04)
Feb	($1.36)	($1.14)	($1.59)
Mar	($1.18)	($0.44)	($2.04)
Apr	($1.04)	($0.37)	($1.76)
May	($0.97)	($0.25)	($1.72)
Jun	($1.45)	($0.80)	($2.28)
Jul	$1.10	$3.82	($1.57)
Aug	($0.40)	$0.72	($1.85)
Sep	($1.64)	($0.92)	($2.46)
Oct	($1.15)	($0.73)	($1.59)
Nov	($1.37)	($0.73)	($2.04)
Dec	($1.78)	($1.17)	($2.37)
Annual	($0.92)	($0.06)	($1.85)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-24. The smallest zonal all hours' markup component was in the PPL Control Zone, -$1.23 per MWh, while the highest all hours' zonal markup component was in the ComEd Control Zone, -$0.34 per MWh. On peak, the smallest zonal markup was in the PPL Control Zone, -$0.62 per MWh, while the highest markup was in the ATSI Control Zone, $0.77 per MWh. Off peak, the smallest zonal markup was in the DAY Control Zone, -$2.11 per MWh, while the highest markup was in the ComEd Control Zone, -$1.08 per MWh.

Table 2-24 Day-ahead, average, zonal markup component: Calendar year 2011

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.10)	($0.24)	($2.04)
AEP	($1.00)	($0.01)	($2.04)
AP	($0.84)	$0.19	($1.93)
ATSI	($0.58)	$0.77	($2.05)
BGE	($1.14)	($0.36)	($1.98)
ComEd	($0.34)	$0.34	($1.08)
DAY	($1.18)	($0.34)	($2.11)
DLCO	($0.71)	$0.54	($2.07)
Dominion	($0.87)	$0.06	($1.84)
DPL	($1.10)	($0.28)	($1.96)
JCPL	($1.18)	($0.40)	($2.06)
Met-Ed	($1.17)	($0.49)	($1.92)
PECO	($1.11)	($0.30)	($2.00)
PENELEC	($1.08)	($0.42)	($1.82)
Pepco	($1.20)	($0.49)	($1.98)
PPL	($1.23)	($0.62)	($1.90)
PSEG	($1.19)	($0.42)	($2.06)
RECO	($1.20)	($0.55)	($1.96)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-25.

Table 2-25 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-25 Average, day-ahead markup (By price category): Calendar year 2011

	Average Markup Component	Frequency
< $25	($3.70)	3%
$25 to $50	($1.94)	83%
$50 to $75	$0.22	11%
$75 to $100	$3.30	2%
$100 to $125	$8.77	1%
$125 to $150	$3.51	1%
> $150	$18.99	0%

Frequently Mitigated Unit and Associated Unit Adders

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[32] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[33] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[34,35]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder. For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

FMUs and AUs are designated monthly, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[36]

Table 2-26 shows the number of FMUs and AUs in each month of 2011. For example, in December 2011, there were 20 FMUs and AUs in Tier 1, 26 FMUs and AUs in Tier 2, and 51 FMUs and AUs in Tier 3.

Table 2-26 Number of frequently mitigated units and associated units (By month): Calendar year 2011

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	46	22	66	134
February	34	43	60	137
March	30	46	66	142
April	34	45	62	141
May	37	48	59	144
June	31	50	61	142
July	45	32	43	120
August	33	14	44	91
September	18	19	55	92
October	31	24	53	108
November	20	28	49	97
December	20	26	51	97

Figure 2-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

32 110 FERC ¶ 61,053 (2005).
33 OA, Schedule 1 § 6.4.2.
34 114 FERC ¶ 61, 076 (2006).
35 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

36 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through December, 2011

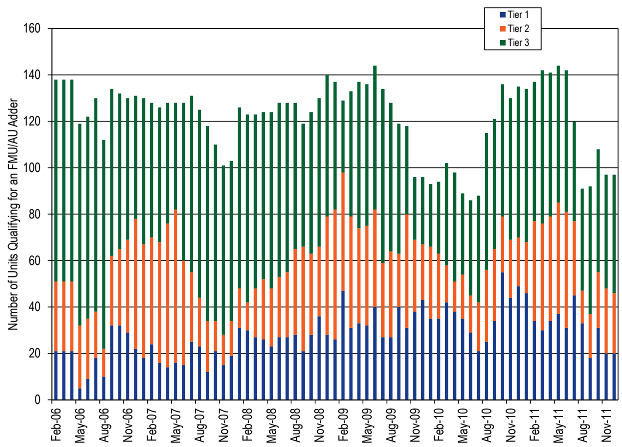


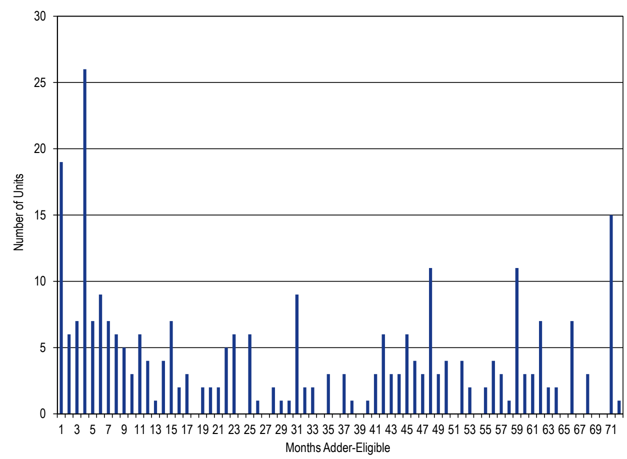
Table 2-27 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2011. Of the 188 units eligible in at least one month during 2011, 88 units (44.6 percent) were FMUs or AUs for more than eight months. Approximately one third of the units (54 units or 28.7 percent) were eligible every month during the year. In 2010, 52 units out of 176 units or 29.5 percent of the units were eligible every month during the year. This demonstrates that the group of FMUs and AUs has been relatively stable over the past year, although units may move between the tier levels, month-to-month.

Table 2-27 Frequently mitigated units and associated units total months eligible: Calendar year 2011

Months Adder-Eligible	FMU & AU Count
1	11
2	1
3	4
4	19
5	12
6	33
7	24
8	14
9	5
10	8
11	3
12	54
Total	188

Figure 2-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through December 31, 2011, there have been 287 unique units that have qualified for an FMU adder in at least one month. Of these 287 units, only one unit qualified for an adder in all potential months. Fifteen additional units qualified in 71 of the 72 possible months, and 121 of the 287 units (42.2 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2011



FMU and AU adders contributed $0.12 per MWh to system average real-time LMP in 2011, out of a real-time, load weighted LMP of $45.94 per MWh.

Energy Market Opportunity Cost

Energy market opportunity costs are the value of a foregone opportunity for a generating unit. Opportunity costs may result when a unit has limited run hours due to an externally imposed environmental limit; is requested to operate for a constraint by PJM; and is offer capped.

The calculation of energy market opportunity costs is designed to calculate the margin (LMP minus cost) for every hour in the projected year for the relevant generator bus. Those margins are the hourly opportunity cost. Opportunity costs are the net revenue from a higher price hour that is foregone as a result of running at PJM's request during a lower price hour. The calculated opportunity cost adder applies only to cost based offers and is only relevant when a unit is offer capped for local market power mitigation.

For example, a unit is limited to 100 run hours for a year based on an environmental regulation. If the unit is required to run by PJM during a low price hour, it can add an opportunity cost to its cost based offer. The value of that opportunity cost adder is the margin from the 100th highest margin hours for the coming year.

In order to calculate the opportunity cost for each hour of the coming year, LMPs and fuel costs must be estimated for each hour of that year. The calculation method uses published forward curves for the price of electricity at the PJM Western Hub and input fuel prices. The forward energy prices are available by month for PJM's West Hub. The forward fuel prices are available by month or by season or quarter and multiple locations.

It is not possible to have margins for individual units at their specific buses using only forward data. In order to develop margins and therefore opportunity costs for individual units at their specific buses, historical data must be used. The historical relationships between hourly prices at the West Hub and the monthly prices at the West Hub are used as the basis for hourly margins. The historical relationships between individual bus prices and the West Hub price are used as the basis for bus specific margins. The historical relationships between daily real time fuel prices and the forward prices are also used to develop the basis for daily, bus specific margins, together with transportation basis differentials.

The result is an hourly LMP estimate for each generator bus, a daily fuel cost estimate for each generator bus and therefore an hourly margin for each bus. (The net margin also accounts for emissions costs, the ten percent adder, VOM and FMU adders.) The hourly LMP and the fuel costs are the result of using the historical ratios multiplied by the forward curve data. The margins which result from comparing these hourly LMP and fuel cost data reflects the forward data, adjusted using historical data, to the specific generator bus. The only purpose of using the historical data is to translate the forward curve data to specific hours and buses.

As of the October 25, 2010, ruling by the Commission, units under energy or regulatory limits imposed by a regulatory agency are able to apply Energy Market Opportunity Costs to cost-based offers.[37] By orders issued March 17, 2011 and October 6, 2011, the Commission approved PJM's proposal to include short-term opportunity costs, rejected PJM's proposed allowance of OMC fuel supply limitations, and rejected PJM's proposed "50/50" rule, which would have permitted generators that were self-scheduling and using up emission-limited hours to have OMC outages.[38] A force majeure standard of fuel supply limitations was approved, and language involving OMC fuel limitations was removed.[39]

Two market participants included opportunity costs as a component of cost based offers in 2011. As the standard opportunity cost methodology did not reflect the market conditions, unit characteristics, and regulatory limitations of this market participant, the MMU approved an alternate method of calculating Energy Market Opportunity Costs for these participants.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Load

Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[40]

PJM Real-Time Load Duration

Figure 2-7 shows the number of hours that PJM real-time accounting load for 2010 and 2011 was within a defined MW range.

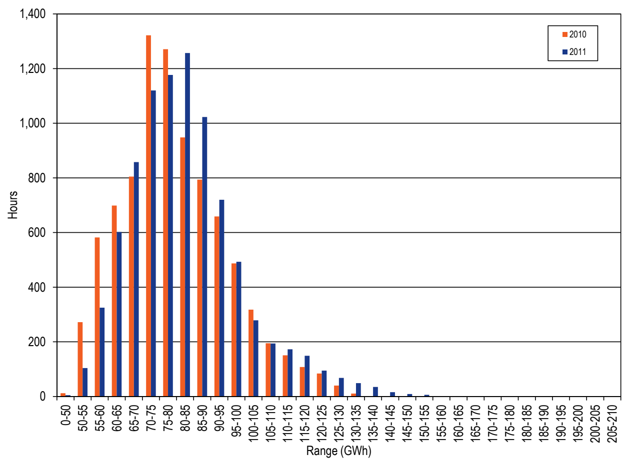
37 133 FERC ¶ 61,081 (2010).

38 134 FERC ¶ 61,192; 137 FERC ¶ 61,017.

39 *Id.*

40 All real-time load data in Section 2, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, Section 5, "Load Definitions," for detailed definitions of accounting load.

Figure 2-7 PJM real-time accounting load histogram: Calendar years 2010 and 2011[41]



PJM Real-Time, Average Load

Table 2-28 presents summary real-time accounting load statistics for the 14 year period 1998 to 2011. The average hourly load of 82,541 MWh in 2011 was 3.7 percent higher than the 2010 annual average hourly load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[42]

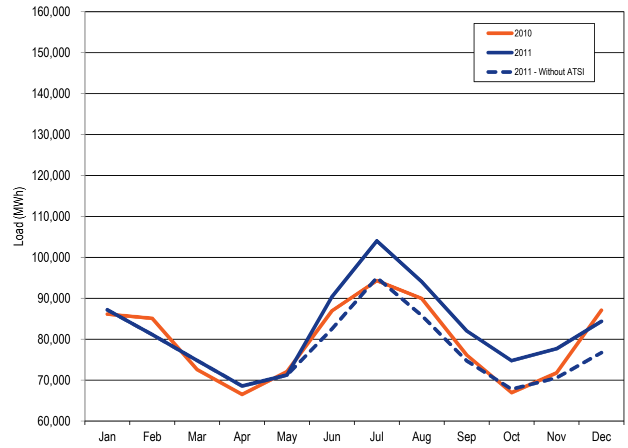
Table 2-28 PJM real-time average hourly load: Calendar years 1998 through 2011

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,956	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,731	8,013	17.9%	36.4%
2003	37,398	6,832	4.7%	(14.7%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,581	14,618	2.7%	0.6%
2008	79,515	13,758	(2.5%)	(5.9%)
2009	76,035	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,541	16,156	3.7%	4.2%

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in 2011 with those in 2010.

Figure 2-8 PJM real-time monthly average hourly load: Calendar years 2010 and 2011



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as the weather variables in the PJM load forecast model for different seasons.[43] THI is a measure of effective temperature using temperature and relative humidity for the cooling season (June, July and August).[44] Table 2-29 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2010 and 2011. When comparing 2011 to 2010, increases in THI were consistent with the increases in load during the cooling months in 2011. For the cooling months of 2011, the average THI was 76.75, 5.1 percent higher than the average 73.01 THI for 2010. The maximum THI (90.55) and minimum THI (59.33) in 2011 were 8.0 percent higher and 5.9 percent higher, than the maximum THI (83.83) and minimum THI (56.02) in 2010 during the cooling months.

41 Each range on the vertical axis includes the start value and excludes the end value.

42 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

43 The weather stations that provided basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

44 Temperature and relative humidity data that were used to calculate THI were obtained from Telvent DTN. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis," Revision 18 (November 16, 2011), Section 3, pp. 9-10.

Table 2-29 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2010 and 2011

	2010			2011			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	56.02	71.64	81.12	59.33	74.29	87.15	5.9%	3.7%	7.4%
Jul	57.22	74.45	83.83	66.74	79.87	90.55	16.6%	7.3%	8.0%
Aug	59.15	72.93	81.41	62.17	76.10	86.08	5.1%	4.3%	5.7%

WWP is the wind-adjusted temperature for the heating season (January, February and December). The average temperature is used for the months not covered by the THI or WWP. Table 2-30 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[45]

Table 2-30 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through 2011

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.47	60.07
2011	76.68	28.42	55.55

Day-Ahead Load

In the PJM Day-Ahead Energy Market, four types of financially binding demand bids are made and cleared:

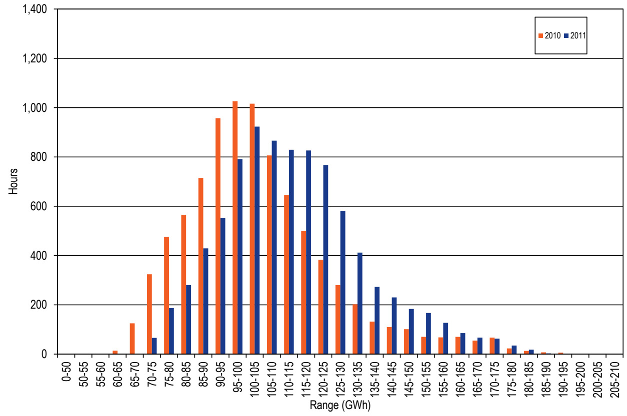
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[46] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the above four types of cleared demand bids.[47]

PJM Day-Ahead Load Duration

Figure 2-9 shows the number of hours that PJM day-ahead load for 2010 and 2011 was within a defined MW range. Compared to the distribution of real-time load in Figure 2-7, the day-ahead distribution has a higher average value, has more occurrences of higher load and is more dispersed over defined MW ranges.

Figure 2-9 PJM day-ahead load histogram: Calendar years 2010 and 2011



45 The Summer THI is calculated by taking average of daily maximum THI in June, July and August. The Winter WWP is calculated by taking average of daily minimum WWP in January, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 18 (November 16, 2011), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

46 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

47 Since an up-to congestion transaction is treated as analogous to a matched pair of INC offers and DEC bids, the DEC portion of the up-to congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation.

Table 2-31 PJM day-ahead average load: Calendar years 2000 through 2011

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2000	33,045	0	33,045	6,850	0	6,850	NA	NA	NA
2001	33,318	76	33,392	6,489	205	6,530	0.8%	NA	1.1%
2002	42,131	196	41,471	10,130	347	12,049	26.5%	159.3%	24.2%
2003	44,340	406	44,735	7,883	353	7,850	5.2%	107.5%	7.9%
2004	61,034	910	61,944	16,318	837	16,603	37.6%	124.1%	38.5%
2005	92,002	1,359	93,369	17,381	796	17,566	50.7%	49.3%	50.7%
2006	94,793	3,681	98,478	16,048	105	16,690	3.0%	170.8%	5.5%
2007	100,912	4,498	105,418	16,190	105	16,656	6.5%	22.2%	7.0%
2008	95,522	6,288	101,287	15,439	106	16,575	(5.3%)	39.8%	(3.9%)
2009	88,707	6,217	94,002	14,896	2,157	16,477	(7.1%)	(1.1%)	(7.2%)
2010	90,985	12,952	103,935	17,014	7,778	21,361	2.6%	108.3%	10.6%
2011	91,713	22,153	113,866	17,830	5,767	20,708	0.8%	71.0%	9.6%

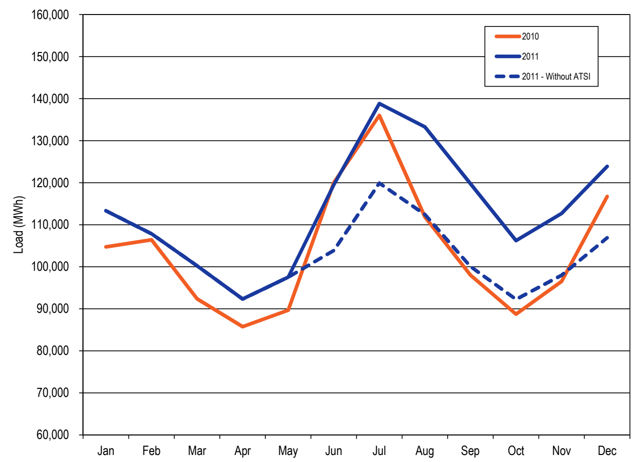
PJM Day-Ahead, Average Load

Table 2-31 presents summary day-ahead load statistics for the 12 year period 2000 to 2011. The average load of 91,713 MWh in 2011 was 0.9 percent higher than in 2010, excluding up-to congestion transactions. When up-to congestion transactions are included in the totals, the average load of 113,866 MWh in 2011 was 9.6 percent higher than in 2010. In 2011, the cleared fixed demand accounted for 69.9 percent, the cleared decrement bids accounted for 9.9 percent, the cleared price sensitive demand accounted for 0.8 percent and up-to congestion transactions accounted for 19.5 percent of average load. The cleared decrement bids were 29.5 percent lower than in 2010, fixed demand was 7.7 percent higher than in 2010, price-sensitive demand was 22.8 percent lower than in 2010 and up-to congestion transactions were 71.0 percent higher than in 2010.

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of 2011 with those of 2010.

Figure 2-10 PJM day-ahead monthly average hourly load: Calendar years 2010 and 2011



Real-Time and Day-Ahead Load

Table 2-32 presents summary statistics for the 2010 and 2011 day-ahead and real-time loads. Total day-ahead load, including up-to congestion transactions, averaged 31,325 MWh more than the real-time load. Total day-ahead load, not including up-to congestion transactions, averaged 9,172 MWh more than the real-time load. Total day-ahead load not including cleared DEC bids or up-to congestion transactions averaged 2,109 MWh less than real-time load. This is the difference between the day-ahead load without virtual transactions and the real-time load. Table 2-32 shows that fixed demand was the largest component of day-ahead load and price-sensitive load was the smallest component.

Table 2-32 Cleared day-ahead and real-time load (MWh): Calendar years 2010 and 2011

		Day Ahead					Real Time	Average Difference	
	Year	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2010	73,853	1,139	15,993	12,952	103,935	79,611	24,324	(4,621)
	2011	79,553	879	11,282	22,153	113,866	82,541	31,325	(2,109)
Median	2010	71,824	1,030	15,850	10,620	100,891	77,430	23,461	(3,009)
	2011	77,556	880	11,086	21,487	111,650	80,870	30,780	(1,793)
Standard Deviation	2010	14,558	474	2,572	7,778	21,361	15,504	5,857	(4,493)
	2011	15,931	181	2,441	5,767	20,708	16,156	4,551	(3,657)
Peak Average	2010	82,017	1,320	17,360	13,587	114,284	88,061	26,223	(4,724)
	2011	88,273	956	12,971	23,194	125,395	91,402	33,993	(2,173)
Peak Median	2010	79,743	1,199	17,249	10,994	108,729	85,413	23,316	(4,927)
	2011	84,790	972	12,747	22,802	122,634	87,930	34,705	(844)
Peak Standard Deviation	2010	12,820	487	2,123	8,314	20,303	13,752	6,551	(3,886)
	2011	14,784	176	1,979	5,862	18,775	14,842	3,933	(3,908)
Off-Peak Average	2010	66,682	981	14,792	12,347	94,646	72,188	22,458	(4,681)
	2011	71,954	812	9,809	21,247	103,822	74,813	29,009	(2,047)
Off-Peak Median	2010	64,834	893	14,601	10,102	91,687	70,322	21,365	(3,338)
	2011	70,251	819	9,571	20,474	102,278	72,661	29,616	(428)
Off-Peak Standard Deviation	2010	11,991	402	2,320	7,250	17,803	12,944	4,859	(4,711)
	2011	12,668	158	1,755	5,525	16,688	12,983	3,705	(3,575)

Figure 2-11 shows the average 2011 hourly cleared volume of fixed-demand bids, the sum of cleared fixed-demand and cleared price-sensitive bids, total day-ahead load and real-time load. The difference between the cleared fixed-demand and cleared price-sensitive bids and the total day-ahead load is cleared decrement bids and up-to congestion transactions. In 2011, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true in 1,502 hours during 2011 (17.1 percent of all hours in 2011). When cleared decrement bids and up-to congestion transactions are included, day-ahead load exceeded real-time load in all hours. When cleared decrement bids are included, but up-to congestion transactions are not included, day-ahead load exceeded real-time load in all hours.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2011

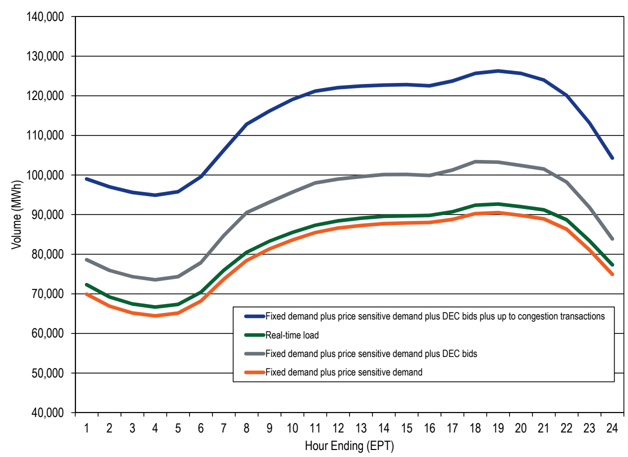
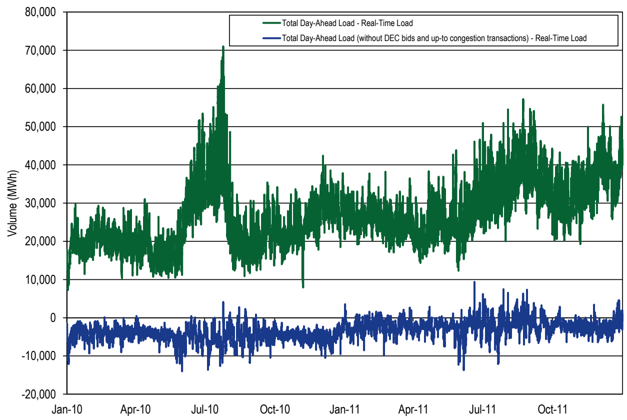


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January 2010 through December 2011



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day. Real-time generation will always be greater than real-time load because of system losses.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[48]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[49]
- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.
- **Increment Offer (INC).** Financial offer to supply specified MWh at corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[50]

In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 2-33 presents summary real-time generation statistics for the 12-year period from 2000 through 2011. The average hourly generation of 85,775 was 3.9 percent higher than in 2010.

Table 2-33 PJM real-time average hourly generation: Calendar years 2000 through 2011

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
Year	Average Generation	Generation Standard Deviation	Average Load	Generation Standard Deviation
2000	29,405	5,130	NA	NA
2001	28,634	5,154	(2.6%)	0.5%
2002	32,414	9,632	13.2%	86.9%
2003	35,337	6,439	9.0%	(33.1%)
2004	50,098	14,738	41.8%	128.9%
2005	79,858	15,137	59.4%	2.7%
2006	80,544	13,184	0.9%	(12.9%)
2007	83,424	13,372	3.6%	1.4%
2008	81,929	13,285	(1.8%)	(0.6%)
2009	78,035	13,647	(4.8%)	2.7%
2010	82,582	15,550	5.8%	13.9%
2011	85,775	15,932	3.9%	2.5%

Table 2-34 presents summary day-ahead generation statistics for the 12 year period from 2000 to 2011. The average generation of 94,977 MWh in 2011, including increment offers, was 0.7 percent higher than in 2010, excluding up-to congestion transactions. When up-to congestion transactions are included, the average generation of 117,130 MWh in 2011 was 9.2 percent higher than in 2010. In 2011, the cleared increment bids were 28.8 percent lower than in 2010.

48 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."

49 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.

50 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

Table 2-34 PJM day-ahead average hourly generation: Calendar years 2000 through 2011

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2000	32,942	0	32,942	15,307	0	6,706	NA	NA	NA
2001	32,966	76	33,042	6,308	205	6,340	0.1%	NA	0.3%
2002	40,849	196	41,045	11,982	347	12,035	23.9%	159.3%	24.2%
2003	43,922	406	44,328	7,822	353	7,779	7.5%	107.5%	8.0%
2004	61,493	910	62,404	17,194	837	17,460	40.0%	124.1%	40.8%
2005	92,911	1,359	94,270	17,440	796	17,621	51.1%	49.3%	51.1%
2006	95,743	3,681	99,424	16,515	105	17,150	3.0%	170.8%	5.5%
2007	103,302	4,498	107,801	16,746	105	17,195	7.9%	22.2%	8.4%
2008	98,487	6,288	104,775	15,996	106	16,404	(4.7%)	39.8%	(2.8%)
2009	90,591	6,217	96,808	15,394	2,157	16,350	(8.0%)	(1.1%)	(7.6%)
2010	94,340	12,952	107,290	17,394	7,778	21,806	4.1%	108.3%	10.8%
2011	94,977	22,153	117,130	18,069	5,767	20,977	0.7%	71.0%	9.2%

Table 2-35 Day-ahead and real-time generation (MWh): Calendar years 2010 and 2011

		Day Ahead				Real Time	Average Difference	
	Year	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2010	83,112	11,243	12,952	107,290	82,582	530	24,708
	2011	86,966	8,010	22,153	117,130	85,775	1,191	31,354
Median	2010	81,197	11,128	10,620	104,135	80,624	573	23,511
	2011	85,218	8,006	21,487	114,938	83,986	1,232	30,951
Standard Deviation	2010	16,715	1,555	7,778	21,806	15,550	1,164	6,256
	2011	17,353	1,313	5,767	20,977	15,932	1,421	5,045
Peak Average	2010	92,259	11,994	13,587	117,839	90,863	1,395	26,976
	2011	96,750	8,859	23,194	128,803	94,275	2,475	34,528
Peak Median	2010	89,688	11,886	10,994	112,413	88,351	1,337	24,062
	2011	93,363	8,753	22,802	126,036	90,828	2,535	35,208
Peak Standard Deviation	2010	14,367	1,460	8,314	20,615	13,798	569	6,817
	2011	15,502	1,048	5,862	18,954	14,683	819	4,272
Off-Peak Average	2010	75,083	10,584	12,347	97,848	75,313	(230)	22,535
	2011	78,442	7,271	21,247	106,960	78,368	73	28,591
Off-Peak Median	2010	73,489	10,564	10,102	94,766	73,441	47	21,325
	2011	76,406	7,216	20,474	105,417	76,389	18	29,028
Off-Peak Standard Deviation	2010	14,336	1,319	7,250	18,213	13,188	1,148	5,025
	2011	14,072	1,048	5,525	16,975	13,013	1,059	3,962

Table 2-35 presents summary statistics for 2011 day-ahead and real-time generation. Day-ahead cleared generation from physical units averaged 1,191 MWh higher than real-time generation, an increase from 503 MWh in 2010. Day-ahead cleared generation from physical units plus cleared INC offers averaged 9,201 MWh more than real-time generation, a decrease from 11,773 MWh in 2010. Day-ahead cleared generation from physical units plus cleared INC offers and up-to congestion transactions averaged 31,354 MWh more than real-time generation, an increase from 24,708 MWh in 2010. This increase is due to the significant increase in up-to congestion transactions in 2011 (an increase from an average of 12,952 MW/hour in 2010 to 22,153 MW/hour in 2011).

Figure 2-13 shows the average 2011 hourly cleared volumes of day-ahead generation without increment offers or up-to congestion transactions, the day-ahead generation including cleared increment bids and up-to congestion transactions and the real-time generation.[51] Real-time generation was less than day-ahead generation from physical units on an hourly average basis. Real-time hourly average generation was lower than day-ahead generation in 65.1 percent of all hours in 2011. Real-time generation was greater than day-ahead generation from physical units for HE 1 through 6, and HE 24. When cleared increment offers and up-to congestion transactions are included, average hourly

51 Generation data are the sum of MWh at every generation bus in PJM with positive output.

total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2011

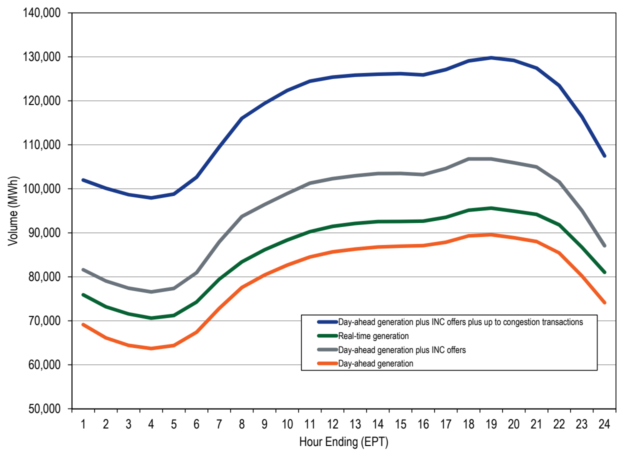
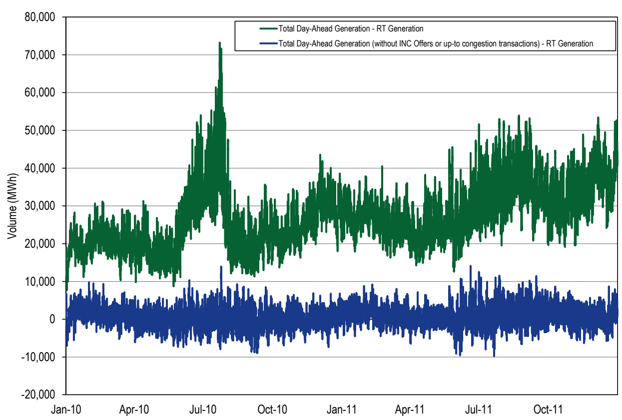


Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2010 through December 2011



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[52]

Real-Time LMP

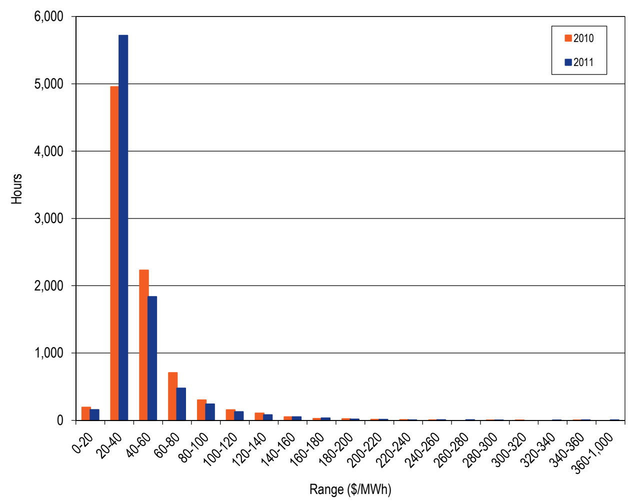
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[53] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the number of hours that PJM real-time average LMP in 2010 and 2011 were within a defined range. As Figure 2-15 shows, the real-time average LMP was less than $100 per MWh during 95.7 percent of the hours in 2010 and 96.2 percent of the hours in 2011.

Figure 2-15 Average LMP histogram for the PJM Real-Time Energy Market: Calendar years 2010 and 2011



PJM Real-Time, Average LMP

Table 2-36 shows the PJM real-time, annual, average LMP for the 14-year period 1998 to 2011.[54] The system average LMP for 2011 was 4.4 percent lower than the 2010 annual average, $42.84 per MWh versus $44.83 per MWh. The PJM real-time, annual, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

52 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

53 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

54 The system annual, average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 2-36 PJM real-time, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-37 shows the PJM real-time, annual, load-weighted, average LMP for the 14-year period 1998 to 2011. The load-weighted, average system LMP for 2011 was 5.0 percent lower than the 2010 annual, load-weighted, average, $45.94 per MWh versus $48.35 per MWh. The PJM real-time, annual, load-weighted, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

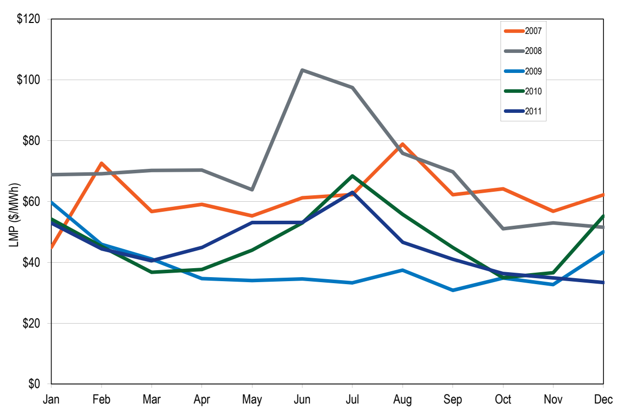
Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2011

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through 2011.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011



Real-Time, Fuel-Cost-Adjusted, Load-Weighted Average LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[55] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2010 and 2011, the 2011 load-weighted LMP was adjusted to reflect the change in the daily price of fuels and emission allowances used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[56]

Of the prices of the primary fuel types used in the PJM footprint, coal and oil increased in price, while on average, natural gas decreased in price in 2011. In 2011, for example, the price of Northern Appalachian coal was 18.4 percent higher than in 2010. The price of Central Appalachian coal was 22.3 percent higher than in 2010. The price of Powder River Basin coal was 7.1 percent higher than in 2010. No. 2 (light) oil prices were 38.6 percent higher and No. 6 (heavy) oil prices were 40.9 percent higher in 2011 than in 2010. Eastern natural gas prices were 9.4 percent lower in 2011 than in 2010. Western natural gas prices were 9.7 percent lower in 2011 than 2010. Figure 2-17 shows spot average fuel prices for 2010 and 2011.[57]

Figure 2-17 Spot average fuel price comparison: Calendar years 2010 through 2011

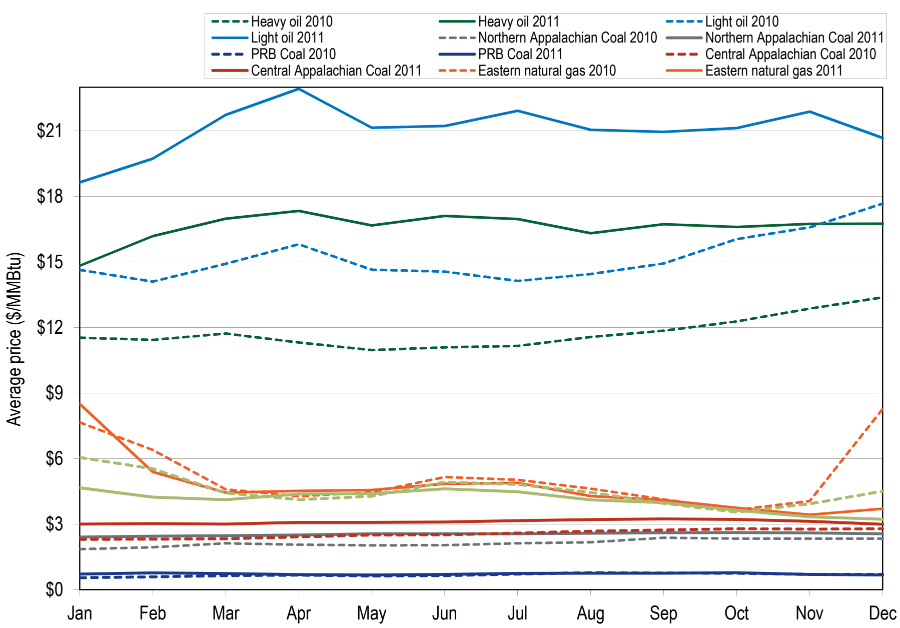


Table 2-38 compares the 2011 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the 2010 load-weighted, average LMP. The fuel-cost adjusted load-weighted, average LMP for 2011 was 2.6 percent lower than the load-weighted, average LMP for 2011. The real-time fuel-cost-adjusted, load-weighted, average LMP in 2011 was 7.4 percent lower than the load-weighted LMP in 2010. If fuel costs for the year 2011 had been the same as for 2010, the 2011 load-weighted LMP would have been lower, $44.75 per MWh instead of the observed $45.94 per MWh. The mix of fuel types and costs in 2011 resulted in higher prices in 2011 than would have occurred if fuel prices had remained at their 2010 levels.

Table 2-38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$45.94	$44.75	(2.6%)
	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$44.75	(7.4%)
	2010 Load-Weighted LMP	2011 Load-Weighted LMP	Change
Average	$48.35	$45.94	(5.0%)

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x,

55 See the *2011 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-15, "Type of fuel used (By marginal units): Calendar year 2011."

56 For more information, see the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity Factors."

57 Eastern natural gas, Western natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

SO_2, and CO_2 and emission allowance costs and unit-specific emission rates, when applicable.

Table 2-39 shows that 46.4 percent of the annual, load-weighted LMP was the result of coal costs, 31.2 percent was the result of gas costs and 1.5 percent was the result of the cost of emission allowances. Markup was 2.8 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than all of the components of the offers of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2011 was $0.02 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-39.[58]

Table 2-39 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$21.30	46.4%
Gas	$14.32	31.2%
10% Cost Adder	$3.95	8.6%
VOM	$2.52	5.5%
Markup	$1.28	2.8%
Oil	$1.21	2.6%
NA	$0.73	1.6%
NOX	$0.31	0.7%
CO2	$0.31	0.7%
FMU Adder	$0.12	0.3%
SO2	$0.04	0.1%
Unit LMP Differential	$0.02	0.1%
Municipal Waste	$0.00	0.0%
Uranium	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.03)	(0.1%)
Dispatch Differential	($0.12)	(0.3%)
Total	$45.94	100.0%

Day-Ahead LMP

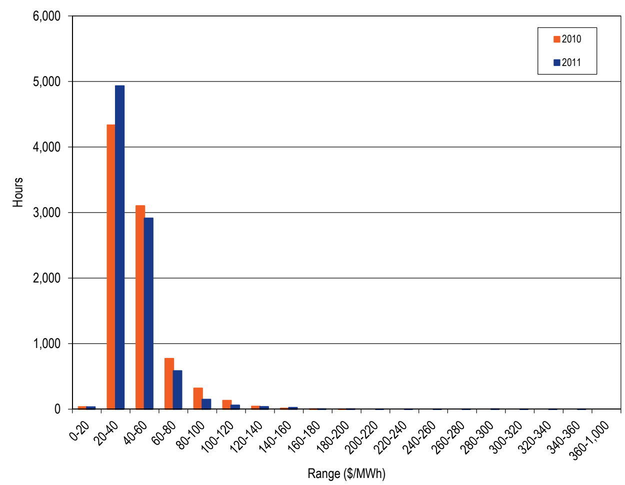
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[59] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-18 shows the number of hours that PJM day-ahead average LMP was within a defined range in 2010 and 2011. As Figure 2-18 shows, day-ahead average LMP was less than $100 per MWh during 97.8 percent of the hours in 2010 and 98.3 percent of the hours in 2011.

Figure 2-18 Price histogram for the PJM Day-Ahead Energy Market: Calendar years 2010 and 2011



PJM Day-Ahead, Annual Average LMP

Table 2-40 shows the PJM day-ahead annual, average LMP for the 12 year period 2000 to 2011. The system average LMP for 2011 was 4.6 percent lower than the 2010 annual average, $42.52 per MWh versus $44.57 per MWh. The PJM day-ahead annual, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

58 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

59 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Day-Ahead LMP.

Table 2-40 PJM day-ahead, average LMP (Dollars per MWh): Calendar years 2000 through 2011

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-41 shows the PJM day-ahead, annual, load-weighted, average LMP for the 12-year period 2000 to 2011. The day-ahead, load-weighted, average LMP for 2011 was 5.2 percent lower than the 2010 annual, load-weighted, average, $45.19 per MWh versus $47.65 per MWh. The PJM day-ahead, load-weighted, average LMP in 2011 was lower than the average LMP in every year from 2005 through 2008.

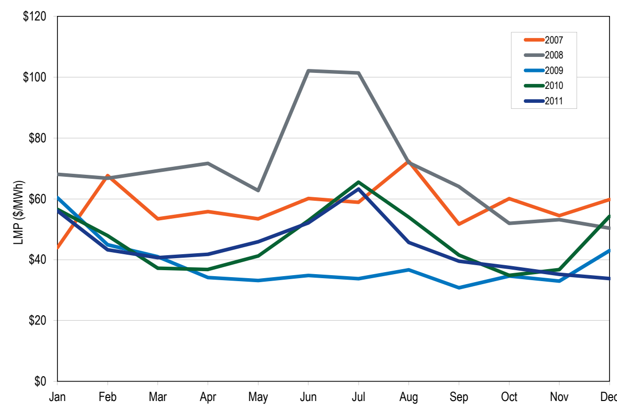
Table 2-41 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through 2011

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-19 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through 2011.

Figure 2-19 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through 2011



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and price sensitive transactions are dispatchable injections and withdrawals in the Day Ahead market. To the extent that INCs, DECs or transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Using identified marginal resource offers and the components of the offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors. Table 2-42 shows the components of the PJM day ahead, annual, load-weighted average LMP.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Day Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[60]

Table 2-42 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2011

Element	Contribution to LMP	Percent
Coal	$12.57	27.8%
DEC	$11.21	24.8%
INC	$7.27	16.1%
Gas	$5.51	12.2%
10% Cost Adder	$1.98	4.4%
Price Sensitive Demand	$1.85	4.1%
Up-to Congestion Transaction	$1.70	3.8%
Dispatchable Transaction	$1.41	3.1%
VOM	$1.30	2.9%
DASR LOC Adder	$0.52	1.2%
NO_x	$0.16	0.4%
CO_2	$0.16	0.4%
Oil	$0.14	0.3%
DASR offer Adder	$0.09	0.2%
SO_2	$0.02	0.0%
FMU Adder	$0.02	0.0%
Constrained Off	$0.00	0.0%
Wind	$0.00	(0.0%)
Markup	($0.92)	(2.0%)
NA	$0.19	0.4%
Total	$45.19	100.0%

Virtual Offers and Bids

The PJM Day-Ahead Energy Market includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. In addition, the PJM Day-Ahead Energy Market includes up-to congestion transactions. Up-to congestion transactions are treated as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids, and affect the outcome of the PJM Day-Ahead Energy Market. Since increment offers, decrement bids and up-to congestion transactions do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

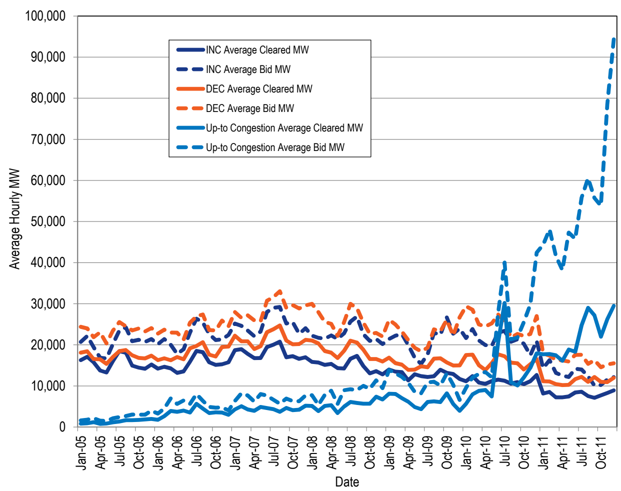
60 New Jersey withdrew from RGGI, effective January 1, 2012.

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids and up-to congestion transactions as financial instruments that do not require physical generation or load. Increment offers, decrement bids and up-to congestion transactions may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.[61] Table 2-43 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-44 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-45 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2011.[62] Together, increment offers and decrement bids represented 19.9 percent of the marginal bids or offers in 2011.

Figure 2-20 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2011



61 An import up-to congestion transaction must source at an interface, but may sink at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. An export up-to congestion transaction may source at any hub, transmission zone, aggregate, or single bus for which LMP is calculated, but must sink at an interface. Wheeling up-to congestion transactions must both source and sink at an interface.

62 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Table 2-43 Hourly average volume of cleared and submitted INCs, DECs by month: Calendar years 2010 and 2011

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	11,144	21,634	282	936	17,513	29,406	266	893
2010	Feb	12,387	23,827	387	1,122	17,602	28,542	270	883
2010	Mar	10,811	21,062	308	915	15,019	24,968	253	763
2010	Apr	10,512	19,940	289	784	13,875	24,458	246	705
2010	May	11,165	19,744	218	806	15,556	25,194	223	787
2010	Jun	11,534	22,956	254	1,496	17,689	27,422	258	1,246
2010	Jul	11,276	23,414	250	1,585	17,223	25,690	304	1,284
2010	Aug	10,567	20,751	226	1,332	15,656	21,745	327	1,140
2010	Sep	10,944	21,365	263	1,232	15,522	22,646	311	1,072
2010	Oct	10,454	20,253	234	1,129	14,011	22,154	253	1,030
2010	Nov	11,134	17,495	220	1,035	15,315	22,618	271	1,055
2010	Dec	12,656	20,957	277	1,340	16,560	26,995	274	1,266
2010	Annual	11,208	21,101	267	1,143	15,952	25,135	271	1,011
2011	Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1,672	11,071	17,355	230	1,034
2011	Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1,084	11,648	17,542	279	1,015
2011	Jul	8,595	14,006	185	1,234	12,196	17,567	213	1,140
2011	Aug	7,540	12,349	120	1,034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867

Table 2-44 Hourly average of cleared and submitted up-to congestion bids by month: Calendar years 2010 and 2011

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2010	Jan	5,647	9,549	114	189
2010	Feb	7,961	12,047	150	244
2010	Mar	8,796	12,916	149	234
2010	Apr	9,004	13,398	137	215
2010	May	7,430	12,114	131	208
2010	Jun	20,537	27,576	168	266
2010	Jul	30,176	40,006	202	336
2010	Aug	10,902	21,354	150	287
2010	Sep	10,114	21,777	156	488
2010	Oct	12,044	25,544	195	473
2010	Nov	14,380	29,788	261	602
2010	Dec	17,928	42,414	319	724
2010	Annual	12,910	22,374	178	355
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Oct	21,985	53,830	616	1,345
2011	Nov	26,234	78,486	718	1,682
2011	Dec	29,471	94,316	720	1,837
2011	Annual	22,067	55,338	557	1,234

Table 2-45 Type of day-ahead marginal units: Calendar year 2011

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	10.5%	0.2%	63.9%	14.8%	10.2%	0.3%
Feb	10.0%	0.4%	67.0%	13.3%	9.1%	0.2%
Mar	8.9%	0.2%	66.4%	16.4%	7.8%	0.3%
Apr	7.6%	0.4%	66.0%	16.4%	9.3%	0.2%
May	5.3%	0.3%	73.2%	13.6%	7.2%	0.3%
Jun	8.0%	0.3%	66.4%	15.7%	9.2%	0.4%
Jul	5.3%	0.1%	68.3%	16.1%	9.8%	0.3%
Aug	4.6%	0.1%	76.2%	11.8%	7.0%	0.3%
Sep	8.0%	0.2%	72.3%	12.5%	6.9%	0.3%
Oct	6.1%	0.1%	74.2%	11.2%	8.1%	0.3%
Nov	3.9%	0.1%	79.9%	9.4%	6.6%	0.1%
Dec	4.5%	0.0%	83.7%	7.2%	4.4%	0.1%
Annual	6.3%	0.2%	73.4%	12.4%	7.5%	0.2%

In order to evaluate the ownership of virtual bids, the MMU categorized all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 2-46 shows the total increment offers and decrement bids by the type of parent organization: financial or physical.[63] Table 2-47 shows the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-46 PJM INC and DEC bids by type of parent organization (MW): Calendar years 2010 and 2011

	2010		2011	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	174,249,033	43.02%	125,432,065	42.99%
Physical	230,775,843	56.98%	166,308,872	57.01%
Total	405,024,876	100.0%	291,740,937	100.0%

Table 2-47 PJM up-to congestion transactions by type of parent organization (MW): Calendar years 2010 and 2011

	2010		2011	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	110,269,067	97.25%	187,509,868	96.84%
Physical	3,121,859	2.75%	6,113,860	3.16%
Total	113,390,926	100.0%	193,623,729	100.00%

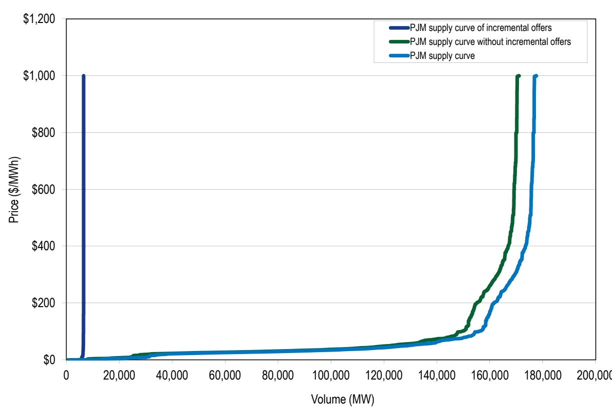
Table 2-48 shows increment offers and decrement bids bid by top ten locations.[64] In 2011, more offers and bids were submitted at the WESTERN HUB than any other location. Total increment offer and decrement bid MW at WESTERN HUB were 25.5 percent of the total PJM offered bids. The top ten locations for increment offers and decrement bids accounted for 55.7 percent of all offers and bids in PJM in 2011.

Table 2-49 shows up-to congestion transactions by import, export and wheel for the top ten locations. For import transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of MISO and the sink of the Northern Illinois Hub. This path accounted for 3.6 percent of all import up-to congestion transactions. The top ten path combinations for import transactions accounted for 18.8 percent of all import up-to congestion transactions. For export transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of the Lumberton aggregate and the sink of the Southeast aggregate. This path accounted for 7.1 percent of all export up-to congestion transactions. The top ten path combinations for export transactions accounted for 23.1 percent of all export up-to congestion transactions.

For wheeling transactions, in 2011, the highest volume of cleared MW occurred on the path with the source of the CPLEIMP interface and the sink of the NCMPAEXP interface. This path accounted for 12.4 percent of all wheeling up-to congestion transactions. The top ten path combinations for wheeling transactions accounted for 54.9 percent of all wheeling up-to congestion transactions.

Figure 2-21 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in June 2011. There were average hourly increment offers of 6,511 MW and average hourly total offers of 176,664 MW for the example day.

Figure 2-21 PJM day-ahead aggregate supply curves: 2011 example day



63 There was an error in the classification of Financial and Physical participants in the initially published *2009 State of the Market Report for PJM*, which was corrected in the errata to the 2009 report published at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-errata.pdf>.

64 There was an error in the information about virtual offers at the top ten aggregates in the *2009 State of the Market Report for PJM*, which was corrected in the errata to the 2009 report published at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-errata.pdf>.

Table 2-48 PJM virtual offers and bids by top ten locations (MW): Calendar years 2010 and 2011

2010					2011				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/ Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	59,498,730	67,461,162	126,959,892	WESTERN HUB	HUB	34,784,275	39,727,544	74,511,819
N ILLINOIS HUB	HUB	12,227,336	13,489,896	25,717,232	N ILLINOIS HUB	HUB	10,740,204	17,271,222	28,011,425
AEP-DAYTON HUB	HUB	5,903,338	7,754,930	13,658,269	AEP-DAYTON HUB	HUB	8,161,997	9,878,692	18,040,689
PPL	ZONE	524,776	8,491,950	9,016,726	SOUTHIMP	INTERFACE	11,363,163	0	11,363,163
PSEG	ZONE	2,412,903	5,229,766	7,642,670	MISO	INTERFACE	292,005	8,755,249	9,047,254
BGE	ZONE	3,675,033	3,624,029	7,299,062	PECO	ZONE	2,080,316	5,855,528	7,935,844
PEPCO	ZONE	5,922,591	1,215,146	7,137,737	PPL	ZONE	318,717	4,727,485	5,046,202
JCPL	ZONE	3,939,569	2,210,312	6,149,881	COMED	ZONE	3,208,552	243,813	3,452,365
MISO	INTERFACE	1,223,081	3,768,471	4,991,553	IMO	INTERFACE	2,754,598	108,998	2,863,597
COMED	ZONE	2,251,251	2,422,361	4,673,613	PSEG	ZONE	544,733	1,740,038	2,284,771
Top ten total		97,578,609	115,668,025	213,246,633			74,248,561	88,308,567	162,557,128
PJM total		184,846,624	220,178,252	405,024,876			130,593,253	161,147,684	291,740,937
Top ten total as percent of PJM total		52.8%	52.5%	52.7%			56.9%	54.8%	55.7%

Table 2-49 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): Calendar years 2010 and 2011

2010														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	COMED	ZONE	3,479,436	COMED	ZONE	MISO	INTERFACE	3,216,407	SOUTHIMP	INTERFACE	SOUTHEXP	INTERFACE	3,014,673
MISO	INTERFACE	DAY	ZONE	3,131,119	BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	2,800,821	NCMPAIMP	INTERFACE	NCMPAEXP	INTERFACE	2,129,852
MISO	INTERFACE	112 WILTON	EHVAGG	2,918,147	DAY	ZONE	MISO	INTERFACE	2,760,390	NORTHWEST	INTERFACE	NIPSCO	INTERFACE	795,172
MISO	INTERFACE	COOK	EHVAGG	2,840,633	23 COLLINS	EHVAGG	MISO	INTERFACE	2,043,536	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	653,232
MISO	INTERFACE	AEP-DAYTON HUB	HUB	2,349,595	ROCKPORT	EHVAGG	MISO	INTERFACE	1,836,300	MISO	INTERFACE	OVEC	INTERFACE	204,838
NYIS	INTERFACE	PSEG	ZONE	1,743,747	COOK	EHVAGG	MISO	INTERFACE	1,331,189	NORTHWEST	INTERFACE	MISO	INTERFACE	201,636
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	1,660,718	MT STORM	EHVAGG	MISO	INTERFACE	1,076,845	NORTHWEST	INTERFACE	IMO	INTERFACE	165,740
MISO	INTERFACE	GREENLAND GAP	EHVAGG	942,071	21 KINCA ATR24304	AGGREGATE	MISO	INTERFACE	1,012,193	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	131,010
NYIS	INTERFACE	MARION	AGGREGATE	940,157	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	892,080	OVEC	INTERFACE	MISO	INTERFACE	118,225
NORTHWEST	INTERFACE	COMED	ZONE	779,805	QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	729,155	OVEC	INTERFACE	SOUTHEXP	INTERFACE	93,177
Top ten total				20,785,428					17,698,915					7,507,555
PJM total				55,024,722					49,156,193					9,210,022
Top ten total as percent of PJM total				37.8%					36.0%					81.5%

2011														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	3,763,388	LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	6,076,609	CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
MISO	INTERFACE	112 WILTON	EHVAGG	2,649,235	WESTERN HUB	HUB	MISO	INTERFACE	3,932,018	CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	2,419,245	23 COLLINS	EHVAGG	MISO	INTERFACE	1,684,900	NORTHWEST	INTERFACE	MISO	INTERFACE	239,020
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	2,205,202	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,591,281	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	2,103,635	FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,363,004	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	174,891
NYIS	INTERFACE	MARION	AGGREGATE	1,674,479	167 PLANO	EHVAGG	MISO	INTERFACE	1,166,857	NYIS	INTERFACE	MICHFE	INTERFACE	115,574
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	1,645,825	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,157,710	MISO	INTERFACE	NIPSCO	INTERFACE	114,199
NYIS	INTERFACE	PSEG	ZONE	1,158,004	BELMONT	EHVAGG	OVEC	INTERFACE	992,732	NIPSCO	INTERFACE	OVEC	INTERFACE	93,186
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,043,124	FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	969,853	NIPSCO	INTERFACE	MISO	INTERFACE	73,321
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	986,945	RECO	ZONE	IMO	INTERFACE	847,660	NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				19,649,082					19,782,624					1,762,903
PJM total				104,786,982					85,627,554					3,209,193
Top ten total as percent of PJM total				18.8%					23.1%					54.9%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk, that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive

Table 2-50 Day-ahead and real-time average LMP (Dollars per MWh): Calendar years 2010 and 2011[65]

	2010				2011			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$44.57	$44.83	$0.26	0.6%	$42.52	$42.84	$0.32	0.7%
Median	$39.97	$36.88	($3.09)	(8.4%)	$38.13	$35.38	($2.75)	(7.8%)
Standard deviation	$18.83	$26.20	$7.38	28.2%	$20.48	$29.03	$8.55	29.4%
Peak average	$52.67	$53.25	$0.58	1.1%	$50.45	$51.20	$0.74	1.4%
Peak median	$45.48	$43.20	($2.29)	(5.3%)	$44.56	$40.25	($4.31)	(10.7%)
Peak standard deviation	$20.07	$28.93	$8.85	30.6%	$24.60	$36.11	$11.51	31.9%
Off peak average	$37.46	$37.44	($0.02)	(0.1%)	$35.61	$35.56	($0.05)	(0.1%)
Off peak median	$33.73	$31.83	($1.90)	(6.0%)	$32.43	$31.58	($0.85)	(2.7%)
Off peak standard deviation	$14.27	$20.93	$6.66	31.8%	$12.44	$18.07	$5.63	31.2%

to negative (Figure 2-22). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-23).

As Table 2-50 shows, day-ahead and real-time prices were relatively close, on average, in 2010 and 2011. The annual average LMP in the Real-Time Energy Market was $0.32 per MWh or 0.7 percent higher than the annual average LMP in the Day-Ahead Energy Market in 2011.

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2011, the real-time, load-weighted, hourly LMPs were higher than day-ahead, load-weighted, hourly LMPs by more than $50 per MWh for 214 hours, more than $100 per MWh for 29 hours, more than $150 per MWh for 8 hours and more than $300 per MWh for 3 hours. Although real-time prices were higher than day-ahead prices on average in 2011, real-time prices were lower than day-ahead prices for 64.7 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $12.75 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$6.47 per MWh.

Table 2-51 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2011. From 2000 to 2003, the real-time annual average LMP was lower than the day-ahead annual average LMP. Since 2004, the real-time annual average LMP has been higher than the day-ahead annual average LMP.[66]

Table 2-51 Day-ahead and real-time average LMP (Dollars per MWh): Calendar years 2000 through 2011

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.0%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%

Table 2-52 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for calendar years 2007 through 2011. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2007 to calendar year 2011, LMP differences occurred predominantly in the range between -$50 per MWh and $50 per MWh. The largest PJM real-time and day-ahead load-weighted hourly LMP difference occurred in the calendar year of 2011 where 3 hourly price differences were greater than $500 per MWh. In 2007, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead load-weighted hourly LMP

65 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

66 Since the Day-Ahead Energy Market starts from June 1, 2000, the data in 2000 starts from June 1, 2000. However, the starting date for years 2001 to 2008 is January 1.

Table 2-52 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

differences are less than $150 per MWh in all but 7 hours. In 2009, the PJM real-time and day-ahead load-weighted hourly LMP differences were less than $100 per MWh in all but 5 hours. In 2010, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 11 hours.

Figure 2-22 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2011. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.65 per MWh for the entire year, Figure 2-22 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead load-weighted hourly LMP was $621.55 per MWh for the hour ended 1700 on May 31, 2011, when the real-time load-weighted hourly LMP was $770.58 and the day-ahead load-weighted hourly LMP was $149.03. The large difference between the day-ahead and real-time load-weighted hourly LMP on May 31, 2011 was the result of several unplanned generator outages. A Maximum Emergency Generation Action was issued in order to increase generation above the normal economic limit in order to meet load demands. End-use customers who are registered in PJM's Mandatory Load Management with Long Lead Time were requested to reduce load.

Figure 2-22 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2011

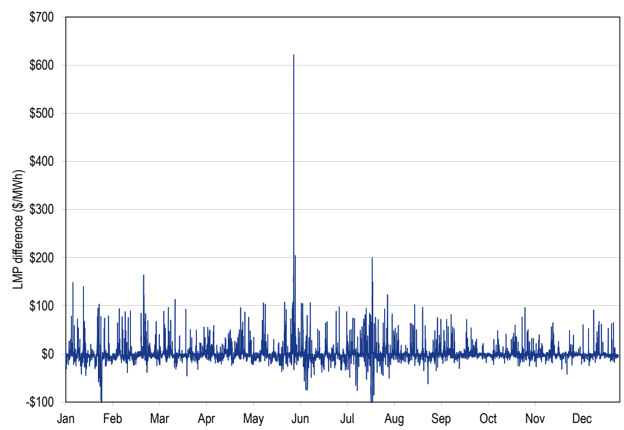


Figure 2-23 shows the monthly average differences between the day-ahead and real-time LMP in 2011. The highest monthly difference was in May.

Figure 2-23 Monthly average of real-time minus day-ahead LMP: Calendar year 2011

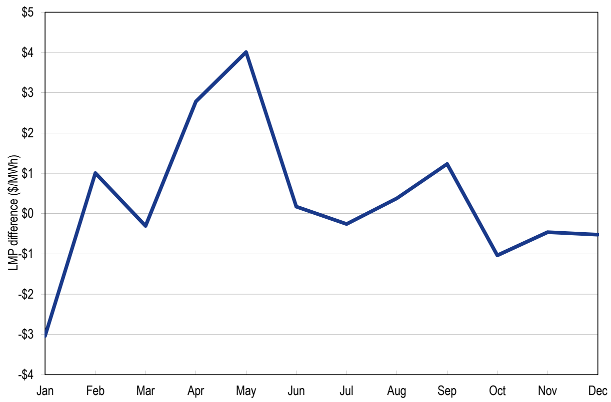
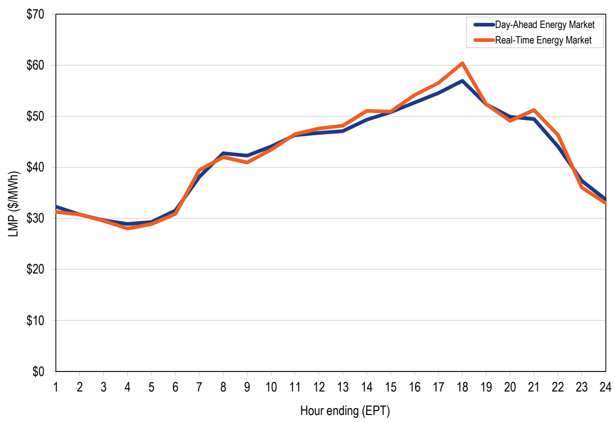


Figure 2-24 shows day-ahead and real-time LMP on an average hourly basis. Real-time average LMP was greater than day-ahead average LMP for 12 out of 24 hours.[67]

Figure 2-24 PJM system hourly average LMP: Calendar year 2011



Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a non-affiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-53 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2010 and 2011 based on parent company. For 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 26.6 percent by spot market purchase and 62.9 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased 1.3 percentage points, reliance on spot supply increased by 6.4 percentage points and reliance on self-supply decreased by 5.1 percentage points.

67 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Table 2-53 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 through 2011

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.0%	17.4%	70.5%	9.3%	28.8%	61.9%	(2.7%)	11.4%	(8.6%)
Feb	13.5%	18.1%	68.4%	10.9%	27.9%	61.2%	(2.6%)	9.8%	(7.2%)
Mar	12.8%	18.2%	68.9%	10.4%	29.3%	60.3%	(2.5%)	11.1%	(8.6%)
Apr	12.6%	19.3%	68.1%	10.7%	25.3%	64.1%	(1.9%)	6.0%	(4.1%)
May	11.6%	19.9%	68.5%	11.1%	25.7%	63.3%	(0.4%)	5.8%	(5.2%)
Jun	10.4%	19.0%	70.5%	10.5%	25.4%	64.1%	0.1%	6.4%	(6.5%)
Jul	9.8%	19.5%	70.7%	9.5%	24.7%	65.8%	(0.3%)	5.2%	(4.9%)
Aug	10.6%	20.5%	68.9%	10.3%	24.6%	65.1%	(0.3%)	4.1%	(3.8%)
Sep	12.0%	22.3%	65.7%	10.9%	26.7%	62.4%	(1.1%)	4.4%	(3.3%)
Oct	13.0%	25.1%	61.9%	12.2%	29.8%	58.0%	(0.8%)	4.7%	(3.9%)
Nov	12.8%	22.7%	64.5%	10.7%	28.3%	61.1%	(2.1%)	5.5%	(3.4%)
Dec	11.5%	21.8%	66.7%	10.1%	24.3%	65.5%	(1.4%)	2.5%	(1.2%)
Annual	11.8%	20.2%	68.0%	10.5%	26.6%	62.9%	(1.3%)	6.4%	(5.1%)

Table 2-54 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 through 2011

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.6%	17.8%	77.6%	4.7%	23.7%	71.6%	0.1%	5.9%	(6.0%)
Feb	4.6%	18.4%	77.0%	5.4%	23.7%	70.9%	0.8%	5.3%	(6.1%)
Mar	4.8%	18.4%	76.8%	5.8%	24.3%	70.0%	1.0%	5.8%	(6.8%)
Apr	4.9%	19.1%	76.0%	6.1%	23.8%	70.1%	1.2%	4.7%	(5.9%)
May	6.6%	19.0%	74.4%	6.0%	24.0%	70.0%	(0.6%)	5.1%	(4.5%)
Jun	4.6%	18.6%	76.7%	6.0%	25.3%	68.8%	1.3%	6.6%	(7.9%)
Jul	4.7%	18.6%	76.6%	5.5%	23.4%	71.2%	0.7%	4.7%	(5.5%)
Aug	4.8%	19.3%	75.9%	5.7%	24.1%	70.1%	1.0%	4.8%	(5.8%)
Sep	4.6%	20.7%	74.8%	5.8%	25.2%	69.0%	1.2%	4.5%	(5.8%)
Oct	4.9%	22.7%	72.4%	5.7%	25.7%	68.5%	0.9%	3.1%	(3.9%)
Nov	4.9%	20.7%	74.4%	6.4%	25.3%	68.3%	1.5%	4.6%	(6.1%)
Dec	4.6%	19.2%	76.2%	6.6%	25.3%	68.1%	2.1%	6.1%	(8.2%)
Annual	4.9%	19.3%	75.8%	5.8%	24.4%	69.8%	0.9%	5.1%	(6.1%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-54 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2010 and 2011, based on parent companies. For 2011, 5.8 percent of day-ahead load was supplied by bilateral contracts, 24.4 percent by spot market purchases, and 69.8 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply increased by 5.1 percentage points, and reliance on self-supply decreased by 6.1 percentage points.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[68] As demand increases and units

68 See *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at Figure 2-1, "Average PJM aggregate supply curves: Summers 2010 and 2011."

with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power. But this is not an efficient way to manage scarcity pricing and makes it difficult to distinguish between market power and scarcity pricing.

The energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This is the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market.

Designation of Maximum Emergency MW

During extreme system conditions when PJM declares Maximum Emergency Alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[69,70] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM direction, to maintain the system during emergency conditions.

Declarations of Hot/Cold Weather Alerts also affect declarations of maximum emergency capacity under the rules. Hot Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation of multiple consecutive days with projected temperatures in excess of 90 degrees with high humidity.[71] Cold Weather Alerts indicate that the system is expected to experience possible resource adequacy issues in the declared areas due to an expectation that temperatures will fall below ten degrees Fahrenheit.[72] A Hot/Cold Weather Alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[73] The Hot/Cold Weather Alert rule regarding Maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the Maximum Emergency Alert rule and its intent. Whereas the Maximum Emergency Alert rule limits maximum emergency designations to capacity with limited availability during extreme system conditions, the Hot/Cold Weather Alert rule defines specific availability limitations which require that capacity be defined as maximum emergency during extreme system conditions.[74]

The indicated references are the only place in the PJM rules and tariff that there is a clear definition of maximum emergency status. The analysis suggests that some MW are inappropriately designated as maximum emergency at times of declared Maximum Emergency Alerts. The analysis also suggests that some MW are inappropriately designated as maximum emergency outside of Maximum Emergency Alerts and Hot/Cold Weather Alerts. Such designations could be considered a form of withholding. There should be a clear definition of maximum emergency status that applies throughout the tariff.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated

69 See PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations p. 1646. Effective Date: 9/17/2010 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 69.

70 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 69: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets." See also PJM Tariff, 6A.1.3 Maximum Emergency Offer Limitations p. 1646.

71 The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 41.

72 The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide when the forecasted weather conditions approach minimum or actual temperatures for the Control Zone fall near or below ten degrees Fahrenheit. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods (refer to Inter RTO Natural Gas Coordination Procedure below). PJM will generally initiate a Cold Weather Alert on a Control Zone basis. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 39.

73 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), pp 37-38. CTs burning oil, kerosene or diesel with less than 16 hours of remaining fuel are considered to be fuel limited during a Hot Weather Alert. CTs burning gas with less than 8 hours of daily fuel allowance are considered to be fuel limited during a Hot Weather Alert. Steam units with less than 32 hours of fuel in inventory are considered to be fuel limited during a Hot Weather Alert.

74 During Maximum Emergency Alert days, PJM rules limit maximum emergency declarations to capacity that falls into one of the following categories: environmentally limited, fuel limited, temporary emergency condition limited, or temporary megawatt additions. See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p 69.

as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

Given the incentives to keep capacity incorrectly designated as maximum emergency under normal system conditions, the rules regarding maximum emergency designations are expected to result in a net decrease in the level of capacity designated as maximum emergency during Maximum Emergency Alerts. This is the case because MW designated as maximum emergency, which do not have to meet a clear standard at other times, must comply with the tariff definition of maximum emergency during Maximum Emergency Alerts. Capacity which was designated as maximum emergency prior to a declaration of Maximum Emergency Alerts but which does not meet this tariff definition be reported as on forced outage or as available economic capacity after such a declaration.

During Maximum Emergency Alert Days in 2011, capacity designated as maximum emergency was used to produce energy in every hour of each day, despite the fact that prices were below $500 and there were no PJM instructions to load the maximum emergency generation. This behavior suggests that these MW designated as maximum emergency were used as economic MW by participants and were therefore incorrectly classified even during Maximum Emergency Alert Days.

Definitions

PJM's current administrative scarcity pricing mechanism is designed to recognize real- time scarcity in the Energy Market and to increase prices to reflect the scarcity conditions. Administrative scarcity pricing results when PJM takes identified emergency actions to support identified scarcity constraints. The scarcity price is based on the highest offer of an operating unit. PJM takes emergency actions on a regional basis when the PJM system is running low on economic sources of energy and reserves. Such actions include voltage reductions, emergency power purchases, manual load dump, and loading of maximum emergency generation.[75,76] These do not represent all of the emergency actions that are available to PJM operators, but the listed steps are defined in the PJM Tariff as the triggers for scarcity pricing events.[77] PJM did not declare any scarcity pricing events in 2011 under PJM's current emergency action based scarcity pricing rules.

This section defines scarcity to exist when the system-wide demand for power exceeds the system-wide capacity available to provide both energy and 10 minute synchronized reserves. There were no such scarcity events in 2011. This section defines a high-load day to exist when hourly total real time demand, including a 30 minute reserve target, equals 96 percent or more of total, within-30 minute supply in the absence of non market administrative intervention, on an hourly integrated basis over a two hour period.[78] There were a total of 35 high-load hours in 2011. There were eight days that met the definition of a high load day in 2011: June 1 and 8, July 20-22 and August 1, 5, and 8.

2011 Results: High-Load Days

There were four Maximum Emergency Alert days in 2011, two in June (June 8 and 9) and two in July (July 21 and 22). Two of the days, June 9 and July 22, had Maximum Emergency Actions for local transmission constraint control which provided for PJM direction to load maximum emergency capacity. Loading maximum emergency capacity to control for local transmission constraints does not trigger scarcity under PJM's current emergency action based scarcity pricing rules. Table 2-55 provides a description of PJM Maximum Emergency Alerts and Actions.

75 A voltage reduction warning (not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 24.

76 "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 29.

77 See OATT, Sheet No. 402A.01.

78 See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 11. The thirty minute reserve target used in the study is the day-ahead operating reserve target based of a percentage of Day Ahead peak load.

Table 2-55 Maximum Emergency Alerts and Actions

Event	Purpose
Maximum Emergency Alert	Day ahead notice that maximum emergency generation has been called into day ahead operating capacity
Maximum Emergency Generation Action Transmission Contingency Support	Real time notice that maximum emergency generation may be required to provide local contingency support
Maximum Emergency Generation Action	Real time notice that maximum emergency generation may be required for system support

Table 2-56 High Load Hour, Hot Weather Alerts and Maximum Emergency Related Events: May through September 2011

Dates	High Load Day (High Load Hours)	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Action Transmission Contingency Support	Maximum Emergency Generation Action
5/26/2011					Southern
5/30/2011		PJM			
5/31/2011		PJM			Mid-Atlantic and Southern
6/1/2011	6				
6/7/2011		ComEd			
6/8/2011	2	PJM	Mid-Atlantic		
6/9/2011		PJM	Mid-Atlantic	BGE	
6/22/2011		Dominion			
7/5/2011	1				
7/11/2011		PJM			
7/12/2011		PJM except ComEd			
7/13/2011		Mid-Atlantic and Dominion			
7/17/2011	1				
7/18/2011		PJM			
7/19/2011		PJM			
7/20/2011	2	PJM			
7/21/2011	6	PJM	Mid-Atlantic		
7/22/2011	5	PJM	Mid-Atlantic	BGE , Mid-Atlantic, DLCO	
7/23/2011		PJM		AE (Atl. City Elec.) - Sub-Trans Zone	
7/28/2011		PJM			
7/29/2011		PJM			
7/30/2011	1	Mid-Atlantic and Southern			
8/1/2011	3	PJM			
8/2/2011		PJM			
8/3/2011		BGE, Pepco, Dominion			
8/5/2011	2				
8/8/2011	6	BGE, Pepco, Dominion			

Table 2-56 shows the relationships among high load days, Hot Weather Alerts, Maximum Emergency Alerts and Maximum Emergency Actions in the May through September period. As defined in this section, there were a total of 35 high-load hours in 2011. There were eleven days with high load hours in June, July and August of 2011: two in June, six in July and three in August. There were eight high load hours in June, sixteen in July and eleven in August. Of those eleven days containing high load hours, seven qualified as high load days, with two or more hours of high load on an hourly integrated basis: June 1 and 8, July 20-22 and August 1 and 8. In the May through September period, PJM declared twenty-two Hot Weather Alerts.[79] Six of the declared Hot Weather Alert days corresponded with the high load day defined in this section: June 8, July 20, 21, 22 and August 1, 8. In the June through August period, PJM declared four maximum emergency alert days, four of which corresponded with the high load day defined in this section: June 8, July 21, July 22 and August 8. Four of the Maximum Emergency Alert days in 2011 were also Hot Weather Alert Days: June 8, 9 and July 21, 22.

In general, participant behavior in the summer of 2011 was consistent with the market incentives created by the Capacity Market and Energy Market. During the

79 "The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days." See PJM. "Manual 13: Emergency Operations," Revision: 47 (Effective January 1, 2012), p. 41.

declared Hot Weather Alerts in 2011, declared outage MW were lower than the average declared outage MW in the June through August period. Maximum emergency generation declarations during maximum emergency generation periods were also lower than the monthly averages in the period. However, energy was produced from declared emergency segments during two Maximum Emergency Alert days, when energy prices were below $500 per MWh and in the absence of specific PJM instructions to load the maximum emergency generation (June 8 and July 21). This behavior suggests that some emergency MW segments were incorrectly classified by the generation owners.

Figure 2-25 and Figure 2-26 show the hourly proportions of maximum emergency capacity that were producing energy on June 9 and July 21 of 2011. June 9 and July 21 were Maximum Emergency Alert Days during which declared emergency MW segments were producing energy, despite the absence of a PJM Maximum Emergency Generation Event. Steam units provided most of the energy from declared, or in excess of declared, emergency segments in every hour of June 9 and July 21. On June 9 and July 21 these maximum emergency MW segments were providing energy in every hour and in all cases they were making this energy available at hourly integrated prices below $500.

Figure 2-25 June 9 hourly declared emergency MW and emergency MW used

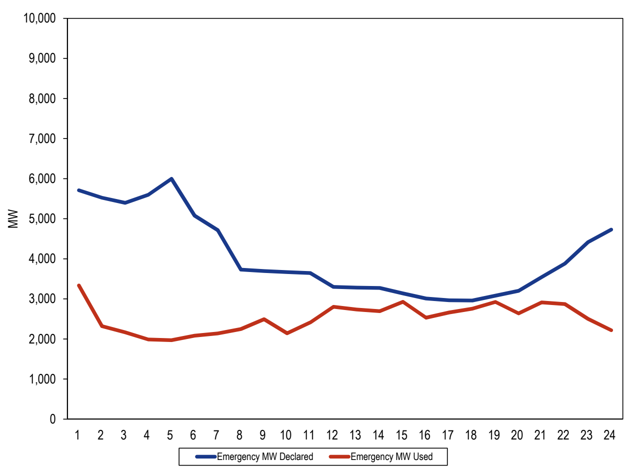
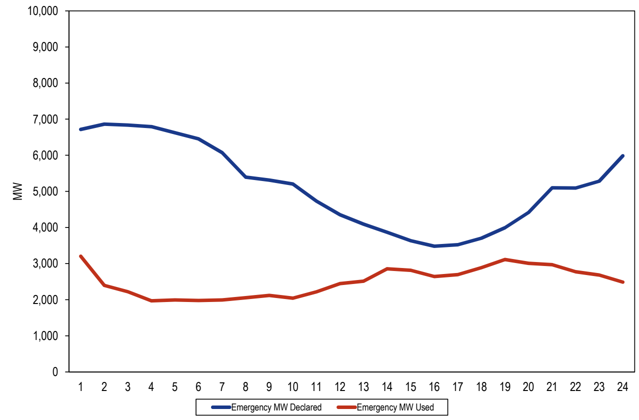


Figure 2-26 July 21 hourly declared emergency MW declared and emergency MW used



Operating Reserve

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges in 2011 were $578.1 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 15.1 percent, the synchronous condensing charges proportion was 0.1 percent, and the balancing charges proportion was 84.8 percent.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.1068 per MWh, the balancing operating reserve RTO deviation rate averaged $0.9455 per MWh and the balancing operating reserve RTO reliability rate averaged $0.0681 per MWh. Lost opportunity cost rate average $1.0678 per MWh and canceled resources rate averaged $0.0560 per MWh.

- **Operating Reserve Credits.** Balancing generator operating reserve credits were 53.3 percent, lost opportunity cost credits were 30.7 percent and day-ahead operating reserve credits were 15.5 percent of all credits. The remaining 0.5 percent was the sum of day-ahead and real-time transactions credits plus synchronous condensing credits.

Characteristics of Credits

- **Types of units receiving operating reserve credits.** Combined cycle and conventional steam units fueled by coal received 91.5 percent of all day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesel engines received 86.7 percent of the lost opportunity cost credits. Wind units received 91.0 percent of the canceled resources credits.

- **Economic – Noneconomic Generation.** In 2011, units receiving balancing operating reserve credits were economic during 34.3 percent of all hours. Combined cycle units had the highest proportion of economic hours with 43.4 percent.

- **Geography of Balancing Credits and Charges.** Generators in the Eastern Region paid 10.1 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 74.1 percent of such credits. Generators in the Western Region paid 10.2 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 25.9 percent of such credits.

- **Generators Credits and Charges.** Generators paid 13.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.6 percent of all credits.

Load Response Resource Operating Reserve Credits

- In 2011, 7.1 percent of all accepted demand reduction bids were paid through operating reserve credits. The remaining 92.9 percent was credited to end-use customers through the economic load response program.

Reactive Service

- Total reactive service credits in 2011 were $41.3 million. The top three zones accounted for 84.0 percent of the total credits. Combustion turbines received 51.5 percent of the total reactive service credits.

Operating Reserve Issues

- The top 10 units receiving total operating reserve credits received 28.1 percent of all credits. The top 10 organizations received 82.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 4710, balancing operating reserves was 3299 and lost opportunity cost HHI was 5385.

- It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits. Of the total balancing operating reserve credits paid to these units, 75.6 percent was allocated as RTO deviation charges, 20.6 percent as RTO reliability charges and the remaining 3.8 percent was allocated regionally.

- Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. In 2011 an estimated total of $6.5 million or 33.6 percent of all balancing operating reserve credits paid to ALR capable units was for the purpose of providing blackstart service.
- Up-to congestion transactions do not pay balancing operating reserve charges despite that they affect dispatch in the Day-Ahead Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant.

Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, PJM should take another step towards more precise definition of the reasons for incurring operating reserve charges and about the necessity of paying operating reserve charges in some cases. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Detailed Recommendations

- The MMU recommends improving the process of identifying and classifying the reasons for paying operating reserve charges to both generation and demand side resources in order to ensure that market transactions pay only appropriate operating reserve charges.
  - The MMU recommends that PJM determine if units are being dispatched for the PSEG – ConEd wheel, that the reasons for the dispatch of these units be logged, and that PJM consider whether the operating reserve charges associated with running these units is being allocated properly.
  - The MMU recommends that PJM dispatchers explicitly log the reasons that ALR units are run out-of-merit to ensure that the resultant operating reserve charges are appropriately assigned to blackstart service or for voltage support.
  - The MMU recommends that after the fact adjustments to the operating reserve charge and credit portions of the bills of PJM members be specifically identified so that they may be properly categorized.

Table 3-1 Operating reserve credits and charges

Credits received for:		Charges paid by:
	Day-Ahead	
Day-Ahead Import Transactions Demand-Side Response Resources Generation Resources	→	Day-Ahead Demand Bid Day-Ahead Export Transactions Decrement Bids
Synchronous Condensing	→	Real-Time Export Transactions Real-Time Load
	Balancing	
Generation Resources: Deviations	→	Real-Time Deviations from Day-Ahead Schedule by RTO, East and West Region
Generation Resources: Reliability	→	Real-Time Load plus Export Transactions by RTO, East and West Region
Canceled Resources Demand-Side Response Resources Lost Opportunity Cost Performing Annual Scheduled Black Start Tests Providing Quick Start Reserve Real-Time Import Transactions	→	Real-Time Deviations from Day-Ahead Schedule in the entire RTO
Controlling Local Transmission Constraints	→	Applicable Requesting Party
Providing Reactive Service	→	Zonal Real-Time Load

— The MMU recommends that lost opportunity cost paid to wind units be properly categorized as such, not as canceled resources credits.

- The MMU recommends that up-to congestion transactions pay balancing operating reserve charges.

Description of Operating Reserves

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the LMP, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 shows the categories of credits and charges and their relationship. This table shows how credits are allocated. Table 3-2 shows the different types of deviations.

Day-Ahead Operating Reserves

Day-ahead operating reserve credits consist of Day-Ahead Energy Market credits and day-ahead import transaction credits.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-7 shows monthly day-ahead operating reserve charges for calendar years 2010 and 2011.

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services; such as voltage regulation.[1]

1 "Manual 28: Operating Agreement Accounting," Revision 50 (January 1, 2012).

Table 3-2 Operating reserve deviations

Day-Ahead	Deviations	Real-Time
Day-Ahead Demand Bid Day-Ahead Sales Day-Ahead Export Transactions Decrement Bids	Demand (Withdrawal) (RTO, East, West)	Real-Time Load Real-Time Sales Real-Time Export Transactions
Day-Ahead Purchases Day-Ahead Import Transactions Increment Offers	Supply (Injection) (RTO, East, West)	Real-Time Purchases Real-Time Import Transactions
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-7 shows monthly synchronous condensing charges for calendar years 2010 and 2011.

Balancing Operating Reserves

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, canceled pool-scheduled resources credits, real-time import transaction credits and credits to resources controlling local transmission constraints. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction, the market participant is made whole. Balancing operating reserve credits are also paid to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Reactive Services

Reactive service credits are paid to units for the purpose of maintaining the reactive reliability of the PJM region if such unit is reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price. Credits are also paid to resources if their output is increased at the request of PJM for the purpose of reactive services and the offered price is higher than the LMP at the unit's bus. Synchronous condensers may also receive reactive service credits by providing synchronous condensing for the purpose of maintaining reactive reliability at the request of PJM. Reactive service charges are allocated daily to real-time load in the transmission zone where the reactive service was provided.

Deviation Categories

Under PJM's operating reserve rules, credits allocated to generators defined to be operating to control deviations on the system, lost opportunity credits and credits to canceled resources are charged to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES) plus day-ahead sale transactions; and b) the sum of real-time load plus real-time sales scheduled through eSchedules plus real-time exports scheduled through the EES.[2,3]
- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES plus day-

2 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.
3 PJM's eSchedules is an application used by participants for internal bilateral transactions.

Table 3-3 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,798,230	3,261,409	3,107,683	16,167,323
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,680,742	12,686,680
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	2,730,454	12,707,988
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,623,238	2,027,200	2,662,761	11,313,199
May	9,004,034	4,228,004	2,416,103	15,648,141	7,144,854	2,381,825	2,902,093	12,428,772
Jun	10,936,989	3,964,478	3,174,230	18,075,697	9,845,466	2,558,697	2,996,041	15,400,204
Jul	10,928,408	3,847,011	3,412,498	18,187,917	10,160,922	2,690,836	3,306,340	16,158,098
Aug	9,747,045	3,417,328	3,188,437	16,352,810	8,566,032	2,057,281	2,907,427	13,530,739
Sep	9,480,237	3,587,356	2,524,213	15,591,806	8,829,765	2,198,858	2,561,534	13,590,157
Oct	7,170,712	2,913,554	2,368,303	12,452,569	7,140,856	2,514,963	2,388,186	12,044,005
Nov	7,606,971	2,860,054	2,485,153	12,952,178	6,739,882	2,704,677	2,949,889	12,394,448
Dec	10,069,627	4,027,236	3,513,489	17,610,352	7,646,566	2,606,633	2,629,846	12,883,045
Total	107,168,079	49,691,893	32,634,039	189,494,011	97,202,725	30,278,937	33,822,997	161,304,659
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	60.3%	18.8%	21.0%	100.0%

ahead purchase transactions; and b) the sum of the real-time purchase transactions scheduled through eSchedules plus real-time imports scheduled through EES.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted. On December 1, 2008, the ramp limited desired (RLD) MW was implemented as a tool to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate. The goal of this rule change was to further incent generators to follow PJM dispatch instruction in order to increase market efficiency, and improve reliability. A deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

Demand and supply deviations are netted by zone, hub, or interface. For example, a negative deviation at a bus can be offset by a positive deviation at another bus in the same zone.

The sum of each organization's netted deviations by zone, hub, or interface is assigned to either the eastern or western region, depending on the location of the zone, hub, or interface.[4] The RTO region deviations are the sum of an organization's eastern and western region deviations, plus deviations that occurred at hubs that include buses in both regions.[5] Generating units that deviate from real-time dispatch may offset deviations by another generating unit at the same bus if that unit is electrically equivalent and owned by the same participant.

An organization's total daily balancing operating reserve charges based on deviations are the sum of the three deviation categories, by region (including the RTO), for the day, multiplied by each regional deviation rate plus lost opportunity cost and canceled resources operating reserve rates.

Table 3-3 shows monthly real-time deviations for demand, supply and generator categories for 2010 and 2011. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were lower in 2011 than 2010 by 28,189,352 MWh or 14.9 percent. Demand deviations decreased by 9.3 percent, supply deviations decreased by 39.1 percent, and generator deviations increased by 3.6. From 2010 to 2011, the share of total deviations in the demand category increased by 3.7 percentage points, the share of supply deviations

4 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ATSI, ComEd, DLCO, and DAY Control Zones.

5 Only two hubs include buses in both the eastern and western regions: the Dominion Hub and the Western Interface Hub.

Table 3-4 Regional charges determinants (MWh): Calendar year 2011

	Reliability Charge Determinants			Deviation Charge Determinants			
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
RTO	722,865,995	32,677,860	755,543,855	97,202,725	30,278,937	33,822,997	161,304,659
East	371,881,388	13,907,345	385,788,732	57,598,101	16,594,151	15,418,402	89,610,653
West	350,984,607	18,770,515	369,755,122	39,199,674	13,557,237	18,404,595	71,161,506

Table 3-5 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

decreased by 7.4 percentage points, and the share of generator deviations increased by 3.8 percentage points.

Real-time load, real-time exports, and deviations in each region are shown in Table 3-4. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Balancing Operating Reserve Allocation

Table 3-5 shows the process for identifying balancing operating reserves credits as related either to reliability or deviations. Credits are assigned to units during two periods, the reliability analysis (performed after the Day-Ahead Market is cleared) and the Real-Time Market.

During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations or to meet forecasted real-time load. Conservative operations mean that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are committed to operate to meet the forecasted real time load plus any operating reserve requirements if needed in addition to the physical units committed in the Day-Ahead Market. The resultant credits are defined as deviation credits.

In the Real-Time Market, credits are also identified as related to either reliability or deviations. Credits are paid to units that are called on by PJM for reliability purposes if the LMP at the unit's bus is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as reliability credits and are allocated to real-time load plus exports.

Credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations.

Reliability and deviations credits are categorized by region based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

Table 3-6 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead Rate ($/MWh)	Balancing RTO Deviation Rate ($/MWh)	Balancing RTO Reliability Rate ($/MWh)
1999	$133,897,428	NA	7.5%	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	0.535*	NA
2001	$290,867,269	34.0%	8.7%	0.275	1.070*	NA
2002	$237,102,574	(18.5%)	5.0%	0.164	0.787*	NA
2003	$289,510,257	22.1%	4.2%	0.226	1.197*	NA
2004	$414,891,790	43.3%	4.8%	0.230	1.236*	NA
2005	$682,781,889	64.6%	3.0%	0.076	2.758*	NA
2006	$322,315,152	(52.8%)	1.5%	0.078	1.331*	NA
2007	$459,124,502	42.4%	1.5%	0.057	2.331*	NA
2008	$429,253,836	(6.5%)	1.3%	0.084	2.113*	NA
2009	$325,842,346	(24.1%)	1.2%	0.120	0.672	0.009
2010	$572,286,706	75.6%	1.6%	0.113	0.912	0.058
2011	$578,072,070	1.0%	1.6%	0.107	0.946	0.068

Operating Reserve Results

Operating Reserve Charges

Table 3-6 shows total operating reserve charges from 1999 through 2011.[6,7] Total operating reserve credits increased by 1.0 percent in 2011 from 2010, to a total of $578.1 million.[8] In 2011, operating reserve charges remained high, 30.2 percent higher than the annual average from 2005 through 2009. Table 3-6 shows the ratio of total operating reserve credits to the total value of PJM billings.[9] This ratio remained the same as 2010 at 1.6 percent.

Table 3-6 shows the average day-ahead operating reserve rate and the average balancing operating reserve RTO deviation rate for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate decreased $0.0062 per MWh or 5.5 percent from $0.1130 per MWh in 2010 to $0.1068 per MWh in 2011. The balancing operating reserve RTO deviation rate increased $0.0335 per MWh, or 3.7 percent, from $0.9120 per MWh in 2010 to $0.9455 per MWh in 2011. The balancing operating reserve RTO reliability rate increased $0.0101 per MWh or 17.4 percent from $0.0580 per MWh in 2010 to $0.0681 per MWh in 2011. The balancing operating reserve RTO deviation rates prior to 2009 (as indicated with asterisk) represent what the rates were under the old operating construct rules, taking each day's total balancing operating reserve credits, and dividing by total demand, supply, and generator deviations.

Total operating reserve charges in 2011 were $578.1 million, up from the total of $572.3 million in 2010. Table 3-7 compares monthly operating reserve charges by category for calendar years 2010 and 2011. The overall increase of 1.0 percent in 2011 is comprised of a 3.7 percent decrease in day-ahead operating reserve charges, a 5.7 percent increase in synchronous condensing charges and a 1.9 percent increase in balancing operating reserve charges. The day-ahead operating reserve charges proportion of total operating reserve charges decreased 0.7 percentage points to 15.1 percent, the synchronous condensing charges proportion remained the same at 0.1 percent, and the balancing charges proportion increased 0.7 percentage points to 84.8 percent.

Table 3-8 shows the monthly composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing generation, real-time import transaction, lost opportunity cost charges, canceled pool-scheduled resources, and charges paid to resources controlling local transmission constraints.

Table 3-9 shows the amount and percentages of regional balancing charge allocations for 2011. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not

6 Table 3-6 includes all categories of credits as defined in Table 3-1 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 16, 2012.

7 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

8 The total operating reserve charges for 2010 were inflated by an import transaction which was made whole through balancing operating reserve credits. Without this transaction, operating reserve charges would have been 4.9 percent higher in 2011.

9 See the *2011 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at Table 10-14, "Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011," for the value of PJM billings during the period indicated.

Table 3-7 Monthly operating reserve charges: Calendar years 2010 and 2011

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,499,142	$50,830,516	$12,373,099	$110,095	$49,326,904	$61,810,098
Feb	$11,425,494	$14,715	$22,453,018	$33,893,227	$8,940,203	$139,287	$26,567,990	$35,647,480
Mar	$8,836,886	$122,817	$17,209,663	$26,169,365	$6,837,719	$66,032	$24,021,865	$30,925,615
Apr	$7,633,141	$93,253	$23,024,746	$30,751,141	$4,405,102	$13,011	$18,762,006	$23,180,118
May	$5,127,307	$131,600	$39,239,806	$44,498,713	$7,064,934	$39,417	$46,178,207	$53,282,558
Jun	$3,511,264	$33,923	$57,141,785	$60,686,972	$8,303,391	$9,056	$62,118,948	$70,431,396
Jul	$4,601,788	$88,136	$63,394,961	$68,084,886	$4,993,311	$238,127	$106,596,647	$111,828,085
Aug	$3,622,670	$66,535	$41,720,756	$45,409,961	$8,360,392	$104,982	$55,142,158	$63,607,531
Sep	$8,433,892	$27,971	$40,808,601	$49,270,464	$6,249,240	$40,878	$36,617,421	$42,907,539
Oct	$7,719,744	$1,543	$30,640,894	$38,362,181	$5,133,837	$0	$20,415,483	$25,549,319
Nov	$6,556,715	$29,674	$20,978,750	$27,565,138	$7,063,847	$0	$19,528,707	$26,592,554
Dec	$12,951,879	$59,954	$83,752,310	$96,764,143	$7,593,046	$0	$24,716,729	$32,309,775
Total	$90,702,132	$720,142	$480,864,432	$572,286,706	$87,318,120	$760,886	$489,993,064	$578,072,070
Share of Annual Charges	15.8%	0.1%	84.0%	100.0%	15.1%	0.1%	84.8%	100.0%

Table 3-8 Monthly balancing operating reserve charges by category: Calendar year 2011

	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Charges due to Local Transmission Constraint	Total
Jan	$43,170,696	$2,946,513	$590,321	$2,619,374	$49,326,904
Feb	$22,698,871	$3,205,948	$168,244	$494,927	$26,567,990
Mar	$15,248,859	$7,094,881	$358,223	$1,319,902	$24,021,865
Apr	$11,094,664	$7,222,704	$303,514	$141,123	$18,762,006
May	$20,285,073	$20,364,971	$2,742,644	$2,785,518	$46,178,207
Jun	$30,605,916	$27,996,648	$901,825	$2,614,560	$62,118,948
Jul	$56,565,647	$46,241,739	$299,606	$3,489,655	$106,596,647
Aug	$29,078,083	$24,142,105	$302,975	$1,618,995	$55,142,158
Sep	$17,735,689	$16,948,063	$151,195	$1,782,474	$36,617,421
Oct	$10,460,806	$6,327,845	$1,250,928	$2,375,903	$20,415,483
Nov	$11,415,410	$6,181,160	$1,663,154	$268,983	$19,528,707
Dec	$20,477,899	$3,574,430	$306,260	$358,140	$24,716,729
Total	$288,837,612	$172,247,007	$9,038,890	$19,869,554	$489,993,064
Share of Annual Charges	58.9%	35.2%	1.8%	4.1%	100.0%

include charges attributed for resources controlling local transmission constraints, resources providing quick start reserve and resources performing annual, scheduled black start tests.

Operating Reserve Rates

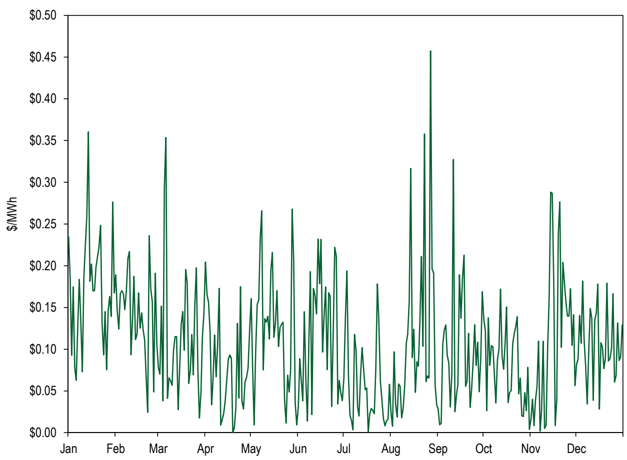
Under the operating reserve cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO. The day-ahead operating reserve rates are equal to the total day-ahead operating reserve credits divided by the sum of the day-ahead demand bids, decrement bids and day-ahead export transactions. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. Lost opportunity cost and canceled resources rates are calculated by dividing each daily credit by the daily demand, supply, and generation deviations. See Table 3-1 and Table 3-5 for how these credits are allocated.

Figure 3-1 shows the daily day-ahead operating reserve rate for 2011. The average rate was $0.1068 per MWh. The highest rate occurred August 27, when the rate reached $0.4574 per MWh mainly because of the precautions taken by PJM due to Hurricane Irene. Day-ahead operating reserve rates also show a weekly pattern. Rates on weekends are on average 61.5 percent higher than rates on weekdays. This could be a result of holding units on during the lower load weekend periods so that they are available on Monday.

Table 3-9 Regional balancing charges allocation: Calendar year 2011[10]

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$49,417,097	10.5%	$9,996,503	2.1%	$27,029,746	5.7%	$86,443,346	18.4%
	Real-Time Exports	$2,032,004	0.4%	$589,969	0.1%	$1,626,901	0.3%	$4,248,873	0.9%
	Total	$51,449,101	10.9%	$10,586,472	2.3%	$28,656,646	6.1%	$90,692,219	19.3%
Deviation Charges	Demand	$92,658,511	19.7%	$25,062,023	5.3%	$4,296,258	0.9%	$122,016,792	26.0%
	Supply	$28,234,803	6.0%	$6,642,217	1.4%	$1,482,909	0.3%	$36,359,930	7.7%
	Generator	$31,622,306	6.7%	$6,223,171	1.3%	$1,923,194	0.4%	$39,768,671	8.5%
	Total	$152,515,621	32.4%	$37,927,411	8.1%	$7,702,362	1.6%	$198,145,393	42.1%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$112,133,882	23.9%	$0	0.0%	$0	0.0%	$112,133,882	23.9%
	Supply	$31,779,830	6.8%	$0	0.0%	$0	0.0%	$31,779,830	6.8%
	Generator	$37,372,185	7.9%	$0	0.0%	$0	0.0%	$37,372,185	7.9%
	Total	$181,285,897	38.6%	$0	0.0%	$0	0.0%	$181,285,897	38.6%
Total Balancing Charges		$385,250,619	81.9%	$48,513,882	10.3%	$36,359,008	7.7%	$470,123,510	100%

Figure 3-1 Daily day-ahead operating reserve rate ($/MWh): Calendar year 2011



The top chart in Figure 3-2 shows the RTO and the regional reliability rates for 2011. The average daily RTO reliability rate was $0.0681 per MWh. On August 26, PJM declared conservative operations in the Mid-Atlantic and Dominion zones for the evening period of Saturday, August 27 and the midnight, day and evening periods of Sunday, August 28 due to Hurricane Irene. The August 28 Eastern region reliability rate was $3.0844 per MWh, the largest in 2011.

The center chart in Figure 3-2 shows the RTO and the regional deviations rates for 2011. The average daily RTO deviation rate for 2011 was $0.9455 per MWh. The largest daily rate occurred on January 24, 2011, when the RTO deviation rate was $10.9541 per MWh.

In 2011, two specific periods experienced higher than normal balancing operating reserve charges, specifically RTO deviation charges. The three days from January 22 through January 24 accounted for 8.8 percent or $17.9 million of all balancing operating reserve charges allocated in the RTO in 2011. The five days from July 19 through July 23, the balancing operating reserve charges allocated in the RTO totaled $18.6 million or 9.1 percent of all balancing operating reserve charges allocated in the RTO in 2011. These days were at or near the time of the peak load days in their respective seasons. January 24 had the highest daily real-time demand of the winter season and five of the top 6 peak load days of 2011 occurred between July 19 and July 23.[11]

The bottom chart in Figure 3-2 shows the daily lost opportunity cost rate and the daily canceled resources rate. The lost opportunity rate averaged $1.0678 per MWh. The highest lost opportunity cost rate occurred on May 31, when it reached $12.7818 per MWh. The canceled resources rate averaged $0.0560 per MWh and credits were paid during 56.4 percent of the days in 2011. Spikes in the lost opportunity cost charge rate are often caused by credits paid to combustion turbines with long start-up and notification time. Combustion turbines with long start-up and notification time are generally not dispatched in real time because their availability is outside the PJM dispatcher window. PJM has proposed a rule change to address this issue.

10 The total charges shown in Table 3-9 do not equal the total balancing charges shown in Table 3-8 because the totals in Table 3-8 include charges to resources controlling local transmission constraints while the totals in Table 3-9 do not.

11 Including PJM's net interface position (real-time imports and exports).

Figure 3-2 Daily balancing operating reserve rates ($/MWh)

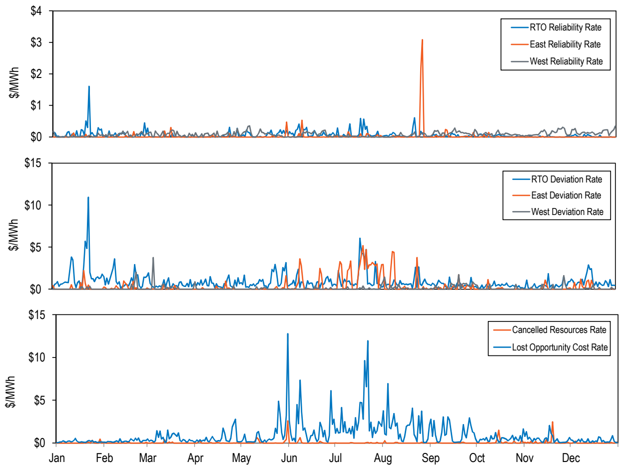


Table 3-10 shows the rates for each region in each category. Regional reliability rates are higher than the RTO reliability rate. RTO deviation charges and lost opportunity cost charges accounted for 66.3 percent of all balancing operating reserve charges in 2011. The RTO deviation and lost opportunity cost rates were substantially higher than the regional deviation rates.

Table 3-10 Balancing operating reserve rates ($/MWh): Calendar year 2011

	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.068	0.946	1.068	0.056
East	0.027	0.423	NA	NA
West	0.078	0.108	NA	NA

Table 3-11 Operating reserve rates statistics ($/MWh): Calendar year 2011

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	18.208	2.249	0.238	2.521
	DEC	18.235	2.358	0.347	2.504
	DA Load	0.457	0.109	0.000	0.073
	RT Load	3.201	0.091	0.000	0.245
	Deviation	18.208	2.249	0.238	2.521
West	INC	17.621	2.001	0.087	2.083
	DEC	17.630	2.110	0.321	2.069
	DA Load	0.457	0.109	0.000	0.073
	RT Load	1.665	0.146	0.000	0.140
	Deviation	17.621	2.001	0.087	2.083

Table 3-11 also shows the operating reserve cost of a 1 MW transaction during 2011. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.3581 per MWh with a maximum rate of $18.2352 per MWh, a minimum rate of $0.3475 per MWh and a standard deviation of $2.5039 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges.

Operating Reserve Credits by Category

Figure 3-3 shows that 84.3 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits. This percentage increased 4.9 percent from the 79.4 percent accumulated in 2010.

Figure 3-3 Operating reserve credits: Calendar year 2011

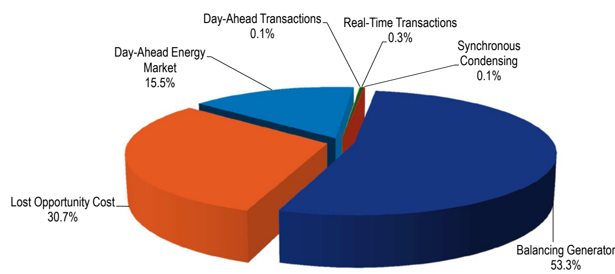


Table 3-12 shows the monthly totals for each type of credit for 2011. The winter months, January, February, November, and December, accounted for 27.4 percent of operating reserve credits for the year, while the summer months, May, June, July and August, accounted for 51.6 percent, and the shoulder months 21.0 percent. These credits do not equal the total amount of charges paid of $578.1 million. The difference of $17.2 million was operating reserve billing adjustments made by PJM directly to participants' bills.[12]

Characteristics of Credits

Types of Units

Table 3-13 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.) Credits to demand resources are not included.

Table 3-14 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and

12 PJM Settlements makes offline adjustments for credits to participants on a continuous basis. The adjusted amount corresponds to charges paid by a transmission owner for local constraint control that were not reflected in the corresponding credits.

Table 3-12 Credits by month (By operating reserve market): Calendar year 2011[13]

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$43,621,831	$473,239	$2,946,513	$59,524,777
Feb	$8,844,162	$96,041	$139,287	$22,983,987	$378,056	$3,205,948	$35,647,482
Mar	$6,830,696	$7,024	$66,032	$15,513,366	$421,862	$7,094,881	$29,933,860
Apr	$4,395,461	$9,641	$13,011	$11,323,487	$215,816	$7,222,703	$23,180,118
May	$7,057,377	$7,557	$39,417	$23,115,911	$13,365	$20,364,971	$50,598,598
Jun	$8,158,879	$144,512	$9,056	$31,865,375	$20,077	$27,996,648	$68,194,548
Jul	$4,972,654	$20,657	$238,127	$56,927,399	$1,068	$46,241,740	$108,401,646
Aug	$8,355,563	$4,828	$104,982	$29,491,930	$4,774	$24,142,105	$62,104,182
Sep	$6,249,124	$116	$40,878	$18,309,027	$40,005	$16,948,063	$41,587,213
Oct	$5,133,838	$0	$0	$11,672,870	$38,865	$6,327,845	$23,173,418
Nov	$7,063,848	$0	$0	$12,994,147	$114,037	$6,181,160	$26,353,192
Dec	$7,593,046	$0	$0	$20,920,854	$43,712	$3,574,430	$32,132,042
Total	$87,007,258	$310,864	$760,885	$298,740,185	$1,764,877	$172,247,006	$560,831,075
Share of Credits	15.5%	0.1%	0.1%	53.3%	0.3%	30.7%	100.0%

Table 3-13 Credits by unit types (By operating reserve market): Calendar year 2011

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Credits due to Local Transmission Constraints	Total
Battery	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	$12,488
Combined Cycle	30.3%	0.0%	65.6%	3.9%	0.2%	0.0%	$112,881,400
Combustion Turbine	2.3%	0.4%	35.3%	61.8%	0.2%	0.0%	$212,434,080
Diesel	0.2%	0.0%	3.4%	96.4%	0.0%	0.0%	$18,695,125
Hydro	39.3%	0.0%	25.7%	0.0%	35.1%	0.0%	$307,331
Nuclear	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$431,172
Steam - Coal	33.9%	0.0%	53.0%	11.2%	0.0%	1.9%	$133,977,613
Steam - Others	3.4%	0.0%	92.3%	4.2%	0.1%	0.0%	$71,789,303
Wind	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	$8,226,822

Table 3-14 Credits by operating reserve market (By unit type): Calendar year 2011

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Credits due to Local Transmission Constraints
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	39.3%	0.0%	25.8%	2.6%	3.0%	0.0%
Combustion Turbine	5.6%	100.0%	26.2%	76.2%	4.0%	1.3%
Diesel	0.0%	0.0%	0.2%	10.5%	0.0%	0.0%
Hydro	0.1%	0.0%	0.0%	0.0%	1.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%
Steam - Coal	52.2%	0.0%	24.7%	8.7%	0.0%	98.7%
Steam - Others	2.8%	0.0%	23.1%	1.8%	0.8%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	91.0%	0.0%
Total	$87,007,258	$760,885	$287,072,737	$172,247,006	$9,038,892	$2,628,556

conventional steam units fueled by coal received 91.5 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 86.7 percent of the lost opportunity cost credits. Wind units received 91.0 percent of the canceled resources credits.

13 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills. Balancing generator credits include canceled resources and credits to resources controlling local transmission constraints.

Wind Unit Credits

PJM calculates credits for scheduled resources that are canceled by PJM before coming on line. PJM credits each participant for cancellations based on actual costs incurred and submitted in writing to PJM. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer. The total cancellation credits are allocated to RTO demand, supply and generator deviations on a daily basis.

PJM categorizes lost opportunity costs credits paid to wind units as canceled resources credits. Canceled resources credits should reflect the actual cost of starting a unit. None of the wind units that received canceled resources credits submitted start-up costs. This categorization does not have any impact on the allocation of the charges since both are allocated to RTO demand, supply and generator deviations. However these credits appear to have been misclassified.

Credits paid to wind units increased considerably in 2011. The total credits paid in 2010 amounted to $1.9 million. In 2011 the total increased to $8.2 million. A total of 11 wind farms were paid credits under the canceled resources category of the operating reserve rules. Table 3-15 shows the monthly canceled resources credits paid to wind farms.

Table 3-15 Canceled resources credits paid to wind units: Calendar year 2011

	Wind Units Canceled Resources Credits	Annual Share
Jan	$419,273	5.1%
Feb	$142,349	1.7%
Mar	$344,622	4.2%
Apr	$271,810	3.3%
May	$2,446,129	29.7%
Jun	$839,074	10.2%
Jul	$167,310	2.0%
Aug	$244,935	3.0%
Sep	$151,194	1.8%
Oct	$1,237,631	15.0%
Nov	$1,663,153	20.2%
Dec	$297,803	3.6%
Total	$8,225,285	100.0%

The AEP and ComEd Control Zones were the only zones with wind units receiving operating reserve credits.

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the day ahead schedule or minimum run time. It is possible for a unit to have a segment during which some hours are economic and some hours are noneconomic. For example, if a unit is turned on to control a constraint, it would be considered economic at that time if the unit set the price in the constrained area or was inframarginal. However, if that unit needs to satisfy a minimum runtime because of physical operating characteristics, the unit may become noneconomic for the remainder of its runtime. Noneconomic and economic status may also change when units are run through the overnight hours in order to be available for morning load pickups.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each hour was first determined to be economic or noneconomic based solely on the unit's hourly energy offer. The hourly energy offer does not include the hourly no-load cost or any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-16 shows the number of economic and noneconomic hours for each unit type. For example, of the 33,493 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit was higher than its real-time energy offer in 14,534 hours, or 43.4 percent of those hours.

Geography of Balancing Credits and Charges

Table 3-17 and Table 3-18 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table 3-17 shows that on average, 10.1 percent of balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 74.1 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-18 also shows that generators in the Western Region paid 10.2 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 25.9 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-16 Economic vs. noneconomic hours: Calendar year 2011

Unit Type	Economic Hours	Economic HoursPercentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Battery	0	0.0%	5	100.0%	5
Combined Cycle	14,534	43.4%	18,959	56.6%	33,493
Combustion Turbine	6,412	25.6%	18,659	74.4%	25,071
Diesel	159	9.5%	1,517	90.5%	1,676
Hydro	2	7.7%	24	92.3%	26
Steam - Coal	25,873	34.8%	48,545	65.2%	74,418
Steam - Others	1,122	19.7%	4,579	80.3%	5,701
Total	48,102	34.3%	92,288	65.7%	140,390

Table 3-17 Monthly balancing operating reserve charges and credits to generators (Eastern Region): Calendar year 2011

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$3,070,704	$291,380	$344,834	$3,706,918	$41,598,008
Feb	$1,576,213	$215,195	$347,413	$2,138,821	$21,168,662
Mar	$978,106	$74,479	$821,184	$1,873,769	$17,326,859
Apr	$863,354	$95,458	$860,974	$1,819,786	$14,084,125
May	$1,449,060	$43,532	$2,271,151	$3,763,743	$26,487,430
Jun	$1,237,386	$744,317	$2,562,452	$4,544,155	$42,604,913
Jul	$2,685,205	$3,189,175	$4,537,061	$10,411,441	$80,396,433
Aug	$925,573	$986,451	$2,195,676	$4,107,700	$42,161,925
Sep	$637,068	$236,673	$1,451,588	$2,325,329	$23,933,140
Oct	$374,150	$79,258	$629,708	$1,083,115	$10,837,188
Nov	$483,347	$67,950	$636,498	$1,187,795	$9,968,778
Dec	$957,032	$199,303	$344,218	$1,500,553	$16,363,481
East Generators Total	$15,237,197	$6,223,171	$17,002,758	$38,463,125	$346,930,942
PJM Total Charges	$152,515,621	$45,629,772	$181,285,897	$379,431,291	$468,358,635
Share	10.0%	13.6%	9.4%	10.1%	74.1%

Table 3-18 Monthly balancing operating reserve charges and credits to generators (Western Region): Calendar year 2011

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,578,577	$47,499	$326,035	$2,952,110	$4,636,283
Feb	$1,522,145	$131,300	$352,814	$2,006,259	$4,526,346
Mar	$870,491	$249,134	$825,573	$1,945,197	$4,953,242
Apr	$815,107	$58,219	$883,301	$1,756,627	$4,320,942
May	$1,518,008	$61,151	$2,747,197	$4,326,356	$16,891,893
Jun	$1,377,451	$67,645	$3,089,719	$4,534,815	$16,879,400
Jul	$2,706,819	$78,287	$4,800,103	$7,585,209	$22,709,492
Aug	$1,249,870	$303,951	$3,119,842	$4,673,663	$11,356,465
Sep	$812,317	$437,602	$1,804,622	$3,054,542	$10,861,799
Oct	$529,500	$141,761	$853,380	$1,524,641	$7,163,528
Nov	$834,089	$271,391	$1,072,998	$2,178,478	$9,176,908
Dec	$1,570,735	$75,254	$493,844	$2,139,833	$7,951,396
West Generators Total	$16,385,110	$1,923,194	$20,369,427	$38,677,731	$121,427,693
PJM Total	$152,515,621	$45,629,772	$181,285,897	$379,431,291	$468,358,635
Share	10.7%	4.2%	11.2%	10.2%	25.9%

Table 3-19 shows that on average in 2011, generator charges were 13.8 percent of all operating reserve charges, excluding charges for resources controlling local transmission constraints which are allocated to the requesting transmission owner, 3.4 percent higher than 2010. Generators received 99.6 percent of all operating reserve credits the remaining 0.4 percent were credits paid to import transactions.

Table 3-19 Percentage of unit credits and charges of total credit and charges: Calendar year 2011

	Generators Share of Total Operating Reserves Charges	Generators Share of Total Operating Reserves Credits
Jan	11.3%	99.2%
Feb	11.8%	98.7%
Mar	12.9%	98.6%
Apr	15.5%	99.0%
May	16.0%	100.0%
Jun	13.4%	99.8%
Jul	16.6%	100.0%
Aug	14.2%	100.0%
Sep	13.1%	99.9%
Oct	11.3%	99.8%
Nov	12.8%	99.6%
Dec	11.4%	99.9%
Average	13.8%	99.6%

Load Response Resource Operating Reserve Credits

End-use customers or their representative may offer demand reduction bids which include the day-ahead LMP above which the end-use customer would not consume, and which may also include shut-down costs. Payment for reducing load is based on the MWh reductions committed in the Day-Ahead market. An end-use customer or representative that submits a load reduction bid day-ahead that is accepted by PJM was paid the day-ahead LMP less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are those charges the participant would have otherwise paid the LSE absent the load reduction.

Total payments to end-use customers or their representative for accepted day-ahead Economic Load Response bids will not be less than the total value of the load response bid, included any submitted shut-down costs. If total payments are less than the total value of the load response bid, PJM will made the resource whole through day-ahead operating reserve credits.

In real-time operations reimbursement for reducing load is based on the actual MWh reduction in excess of committed day-ahead load reductions plus an adjustment for losses. In cases where load response is dispatched by PJM, the total payment to end-use customers or their representative will not be less than the total value of the load response bid, including any submitted shut-down costs. If total payments are less than the total value of the load response bid, PJM will made the resource whole through balancing operating reserve credits.

In 2011, the operating reserve credits for load response decreased by 57.5 percent. This year 7.1 percent of all accepted demand reduction bids were covered by operating reserve credits while the remaining 92.9 percent was paid through the economic load response program as shown in Table 3-20.

Table 3-20 Day-ahead and balancing operating reserve for load response credits: Calendar year 2009 through 2011

	Economic Program Load Response Credits	Operating Reserves for Load Response Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve Credits
2009	$1,389,136	$287,402	82.9%	17.1%
2010	$3,088,049	$363,469	89.5%	10.5%
2011	$2,007,612	$154,589	92.9%	7.1%

Table 3-21 Monthly reactive service credits: Calendar year 2011

	Reactive Service Credits	Percent of Total Reactive Service Credits
Jan	$1,546,278	3.7%
Feb	$1,912,027	4.6%
Mar	$1,438,306	3.5%
Apr	$2,077,101	5.0%
May	$2,712,293	6.6%
Jun	$1,868,004	4.5%
Jul	$929,807	2.3%
Aug	$1,696,735	4.1%
Sep	$2,688,094	6.5%
Oct	$15,523,789	37.6%
Nov	$7,105,062	17.2%
Dec	$1,790,778	4.3%
Total	$41,288,274	100.0%

Table 3-22 Reactive service credits by unit type: Calendar year 2011

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Total Reactive Credits
Combined Cycle	8.2%	15.4%	0.0%	8.8%
Combustion Turbine	56.2%	1.6%	100.0%	51.5%
Diesel	3.9%	0.0%	0.0%	3.6%
Steam - Coal	30.5%	79.6%	0.0%	34.7%
Steam - Others	1.2%	3.3%	0.0%	1.4%
Total	$37,584,680	$3,609,380	$94,214	$41,288,274

Table 3-23 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2011

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%

Reactive Service

Credits to resources providing reactive services are separate from operating reserve credits. These credits are divided into three categories:

- Reactive Service Credit: For units providing reactive services while having an offered price higher than the LMP at the unit's bus.
- Reactive Service Lost Opportunity Cost Credit: For units reduced or suspended by PJM for reactive reliability purposes while having an offered price lower than the LMP at the unit's bus.
- Reactive Service Synchronous Condensing Credit: For units providing synchronous condensing for the purpose of maintaining the reactive reliability of the system.

Total reactive service credits in 2011 were $41.3 million, down from $68.9 million in 2010. Table 3-21 shows the monthly distribution of reactive service credits. In October 37.6 percent of annual credits were paid. During October PJM issued 24 High System Voltage alerts out of an annual total of 37. During this type of system condition PJM calls generators to improve the system reactive reliability by altering their active power output in order to absorb reactive energy.

The top three zones accounted for 84.0 percent of the total, a decrease of 7.5 percent from the 2010 share. The top three zones were the DPL Control Zone, the JCPL Control Zone and the PENELEC Control Zone.

Table 3-22 shows the distribution of credits for each category of reactive service credit received by each unit type. (Each column sums to 100 percent.) Combustion turbines received 51.5 percent of all credits.

Operating Reserve Issues

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

Table 3-24 Operating reserve credits for units (By zone): Calendar year 2011[14]

Zone	Day Ahead Generator	Balancing Generator	Lost Opportunity Cost	Total	Percent of Total Credits
AECO	$430,984	$4,529,506	$4,078,894	$9,039,384	1.6%
AEP - DAY	$3,228,567	$43,573,308	$12,613,913	$59,415,788	11.8%
AP - DLCO	$2,287,456	$12,312,190	$13,153,948	$27,753,595	5.0%
ATSI	$741,167	$1,210,742	$7,256,119	$9,208,028	1.6%
BGE - Pepco	$21,224,868	$57,548,751	$2,477,936	$81,251,555	14.6%
ComEd	$1,314,324	$4,996,562	$17,990,778	$24,301,665	5.2%
Dominion	$6,696,887	$45,183,811	$96,696,281	$148,576,979	26.6%
DPL	$1,824,056	$17,567,397	$4,783,331	$24,174,783	4.3%
JCPL - PSEG	$46,305,825	$76,616,066	$5,614,218	$128,536,109	23.2%
Met-Ed - PPL	$1,355,949	$12,659,910	$2,892,002	$16,907,862	3.0%
PECO	$978,570	$7,227,478	$673,619	$8,879,667	1.7%
PENELEC	$618,605	$3,647,014	$4,015,968	$8,281,586	1.5%
RECO	$0	$0	$0	$0	0.0%
External	$0	$0	$0	$0	0.0%
Total	$87,007,258	$287,072,737	$172,247,006	$546,327,001	100.0%

14 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

The concentration of operating reserve credits remains high, but decreased in 2011 compared to 2010. Table 3-23 shows the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 28.1 percent of total operating reserve credits in 2011, compared to 33.2 percent in 2010. The top 20 units received 38.9 percent of total operating reserve credits in 2011 and 42.2 percent in 2010. In 2011, the top generation owner received 21.0 percent of the total operating reserve credits paid, a decrease from 2010, when the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-24 shows the distribution of operating reserve credits to units by zone. The Dominion Control Zone had the largest share of credits with 26.6 percent, the JCPL and PSEG Control Zones combined had the second highest with 23.2 percent, and the BGE and Pepco Control Zones combined had the third highest with a 14.6 percent share

Table 3-25 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $35.3 million in 2011, or 6.3 percent of the total operating reserve credits paid to all units, a decrease from 2010 when the top unit received 8.3 percent. The cumulative distribution column shows that the top 10 units had a 28.1 percent share of the total operating reserve credits in 2011. The top organization had a 21.0 percent share of the total credits, or $117.9 million, compared to 24.9 percent in 2010. The top 10 organizations receiving credits had a cumulative share of 82.1 percent.

Table 3-26 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $16.5 million, or 18.9 percent of the total day-ahead generator credits, compared to 21.5 percent in 2010. The second unit had a 15.4 percent share, which when combined with the top unit was 34.3 percent of the total credits. The top organization in 2011 received 51.1 percent of the day-ahead credits, which is nearly identical to the 51.0 percent received in 2010. The top 10 organizations received 94.7 percent of the day-ahead credits.

PJM may schedule units in the Day-Ahead Market with a daily total offer higher than the LMP if consistent with cost minimization. For example, a unit might be marginal for one hour and kept scheduled for an additional hour if the alternative cost of running another unit for only one hour is higher than running the first unit for two hours.

Table 3-27 rank orders the top 10 units receiving synchronous condensing credits, and the top organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 99.3 percent of synchronous condensing credits, up from 91.3 percent in 2010.

Table 3-28 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.1 percent of total credits, slightly lower than the 24.5 percent in 2010. The top ten organizations received a total of 67.7 percent of all the balancing generator credits. Units receive balancing operating reserve credits for several reasons. During the real-time operation, PJM may use units to match the generation to the system's demand on a regional basis. Real-time demand, supply and generation deviations from the day-ahead forecast provoke the necessity of using units out of merit order to compensate the variation. Additionally, real-time constraints are also relief by PJM with units that might be marginal for a certain period, but that might have to be kept on-line due to parameters limitations.

Table 3-29 rank orders the top 10 units receiving canceled resources credits, and the top 10 organizations receiving canceled resources credits. The top 10 units received 86.2 percent of the total canceled resources credits and 95.6 percent were received by the top 10 organizations. The top unit receiving canceled resources credits was a wind farm; wind farms received 91.0 percent of all canceled resources credits in 2011.

Table 3-25 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2011

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$35,344,000	6.3%	6.3%	$117,897,474	21.0%	21.0%
2	$28,394,004	5.1%	11.4%	$116,427,595	20.8%	41.8%
3	$21,177,436	3.8%	15.2%	$46,228,293	8.2%	50.0%
4	$18,083,292	3.2%	18.4%	$40,015,254	7.1%	57.2%
5	$12,889,230	2.3%	20.7%	$37,844,468	6.7%	63.9%
6	$8,872,694	1.6%	22.3%	$26,141,774	4.7%	68.6%
7	$8,631,744	1.5%	23.9%	$20,706,101	3.7%	72.3%
8	$8,358,084	1.5%	25.4%	$20,355,568	3.6%	75.9%
9	$7,750,994	1.4%	26.8%	$20,180,674	3.6%	79.5%
10	$7,244,337	1.3%	28.1%	$14,817,890	2.6%	82.1%

Table 3-26 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2011

	Units			Organizations		
Rank	Day-Ahead Generator Credit	Day-Ahead Generator Credit Share	Day-Ahead Generator Credit Cumulative Distribution	Day-Ahead Generator Credit	Day-Ahead Generator Credit Share	Day-Ahead Generator Credit Cumulative Distribution
1	$16,452,908	18.9%	18.9%	$44,438,422	51.1%	51.1%
2	$13,411,194	15.4%	34.3%	$13,923,006	16.0%	67.1%
3	$7,425,138	8.5%	42.9%	$9,426,380	10.8%	77.9%
4	$7,240,542	8.3%	51.2%	$6,017,262	6.9%	84.8%
5	$3,338,557	3.8%	55.0%	$2,479,631	2.8%	87.7%
6	$2,877,342	3.3%	58.3%	$1,972,578	2.3%	89.9%
7	$2,581,422	3.0%	61.3%	$1,312,815	1.5%	91.5%
8	$1,529,182	1.8%	63.0%	$1,169,725	1.3%	92.8%
9	$1,451,224	1.7%	64.7%	$886,604	1.0%	93.8%
10	$1,366,387	1.6%	66.3%	$810,080	0.9%	94.7%

Table 3-27 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2011

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$54,950	7.2%	7.2%	$755,826	99.3%	99.3%
2	$54,772	7.2%	14.4%	$4,692	0.6%	100.0%
3	$51,039	6.7%	21.1%	$368	0.0%	100.0%
4	$50,856	6.7%	27.8%			
5	$46,721	6.1%	34.0%			
6	$46,106	6.1%	40.0%			
7	$44,997	5.9%	45.9%			
8	$44,031	5.8%	51.7%			
9	$43,681	5.7%	57.5%			
10	$40,101	5.3%	62.7%			

Table 3-30 rank orders wind farms and their respective organizations receiving canceled resources credits. The top wind farm received 44.3 percent of all canceled resources credits.

Table 3-31 rank orders the top 10 units receiving credits due to local transmission constraints, and the top 10 organizations receiving credits due to local transmission constraints. Only 6 units received this credit in 2011, owned by 3 organizations. The top organization received 98.7 percent of all credits.

Table 3-32 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 41.5 percent of the total lost opportunity cost credits and 87.9 percent were received by the top 10 organizations.

Table 3-33 rank orders the top 10 units receiving reactive service credits, and the top 10 organizations receiving reactive service credits. The top 3 units received 47.7

Table 3-28 Top 10 units and organizations receiving balancing generator credits: Calendar year 2011

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$27,878,841	9.7%	9.7%	$69,042,449	24.1%	24.1%
2	$18,061,887	6.3%	16.0%	$13,923,006	16.0%	40.1%
3	$12,189,823	4.2%	20.2%	$9,426,380	10.8%	50.9%
4	$11,919,282	4.2%	24.4%	$6,017,262	6.9%	57.8%
5	$8,872,694	3.1%	27.5%	$2,479,631	2.8%	60.7%
6	$7,762,569	2.7%	30.2%	$1,972,578	2.3%	62.9%
7	$7,244,337	2.5%	32.7%	$1,312,815	1.5%	64.4%
8	$7,104,881	2.5%	35.2%	$1,169,725	1.3%	65.8%
9	$5,375,038	1.9%	37.1%	$886,604	1.0%	66.8%
10	$4,417,252	1.5%	38.6%	$810,080	0.9%	67.7%

Table 3-29 Top 10 units and organizations receiving canceled resources credits: Calendar year 2011

	Units			Organizations		
Rank	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution
1	$1,482,845	16.4%	16.4%	$4,282,234	47.4%	47.4%
2	$913,462	10.1%	26.5%	$913,462	10.1%	57.5%
3	$858,854	9.5%	36.0%	$858,854	9.5%	67.0%
4	$797,941	8.8%	44.8%	$732,564	8.1%	75.1%
5	$732,564	8.1%	52.9%	$714,079	7.9%	83.0%
6	$686,899	7.6%	60.5%	$416,195	4.6%	87.6%
7	$679,887	7.5%	68.1%	$220,095	2.4%	90.0%
8	$634,662	7.0%	75.1%	$220,095	2.4%	92.5%
9	$564,877	6.2%	81.3%	$148,252	1.6%	94.1%
10	$440,190	4.9%	86.2%	$135,457	1.5%	95.6%

Table 3-30 Wind farms and respective organizations receiving canceled resources credits: Calendar year 2011

	Wind Farm			Organizations		
Rank	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution	Canceled Resources Credit	Canceled Resources Credit Share	Canceled Resources Credit Cumulative Distribution
1	$3,647,572	44.3%	44.3%	$4,282,234	52.1%	52.1%
2	$1,367,226	16.6%	61.0%	$913,462	11.1%	63.2%
3	$991,119	12.0%	73.0%	$858,854	10.4%	73.6%
4	$858,854	10.4%	83.5%	$732,564	8.9%	82.5%
5	$564,877	6.9%	90.3%	$564,877	6.9%	89.4%
6	$440,190	5.4%	95.7%	$220,095	2.7%	92.1%
7	$134,721	1.6%	97.3%	$220,095	2.7%	94.7%
8	$80,543	1.0%	98.3%	$148,252	1.8%	96.5%
9	$58,558	0.7%	99.0%	$134,721	1.6%	98.2%
10	$44,987	0.5%	99.6%	$77,656	0.9%	99.1%
11	$36,639	0.4%	100.0%	$72,475	0.9%	100.0%

percent of all credits and 93.7 percent of all credits were paid to the top 10 organizations.

Operating Reserves Concentration

In 2011, concentration in all operating reserve credits categories was high. Operating reserves HHI was calculated based on each organization's daily credits for each category. Table 3-34 shows the average HHI for each category. Day-ahead operating reserves HHI was 4710 and it reached 10000 during 4 days of the year. Balancing operating reserve HHI averaged 3299 in 2011. Lost opportunity cost HHI was 5385 and during 6 days of the year lost opportunity credits were paid solely to one supplier.

Table 3-35 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. Table 3-36 shows that 74.7 percent of all credits paid to these units were allocated to deviations while the remaining 25.3 percent were paid for reliability reasons.

Table 3-31 Top 10 units and organizations receiving credits due to local transmissions constraints: Calendar year 2011

	Units			Organizations		
Rank	Credits due to Local Transmission Constraints	Credits due to Local Transmission Constraints Share	Credits due to Local Transmission Constraints Cumulative Distribution	Credits due to Local Transmission Constraints	Credits due to Local Transmission Constraints Share	Credits due to Local Transmission Constraints Cumulative Distribution
1	$1,401,944	53.3%	53.3%	$2,594,890	98.7%	98.7%
2	$717,083	27.3%	80.6%	$32,162	1.2%	99.9%
3	$475,864	18.1%	98.7%	$1,504	0.1%	100.0%
4	$32,162	1.2%	99.9%			
5	$1,052	0.0%	100.0%			
6	$452	0.0%	100.0%			
7						
8						
9						
10						

Table 3-32 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2011

	Units			Organizations		
Rank	Lost Opportunity Cost Credit	Lost Opportunity Cost Credit Share	Lost Opportunity Cost Credit Cumulative Distribution	Lost Opportunity Cost Credit	Lost Opportunity Cost Credit Share	Lost Opportunity Cost Credit Cumulative Distribution
1	$7,583,583	4.4%	4.4%	$71,422,692	41.5%	41.5%
2	$6,766,749	3.9%	8.3%	$20,654,892	12.0%	53.5%
3	$6,128,373	3.6%	11.9%	$14,838,964	8.6%	62.1%
4	$5,969,665	3.5%	15.4%	$10,612,983	6.2%	68.2%
5	$5,068,077	2.9%	18.3%	$8,901,427	5.2%	73.4%
6	$4,979,459	2.9%	21.2%	$5,957,734	3.5%	76.9%
7	$4,422,980	2.6%	23.8%	$5,669,330	3.3%	80.2%
8	$4,161,345	2.4%	26.2%	$4,815,117	2.8%	82.9%
9	$4,053,842	2.4%	28.5%	$4,595,349	2.7%	85.6%
10	$3,718,985	2.2%	30.7%	$3,913,309	2.3%	87.9%

Table 3-33 Top 10 units and organizations receiving reactive service credits: Calendar year 2011

	Units			Organizations		
Rank	Reactive Service Credit	Reactive Service Credit Share	Reactive Service Credit Cumulative Distribution	Reactive Service Credit	Reactive Service Credit Share	Reactive Service Credit Cumulative Distribution
1	$7,032,812	17.0%	17.0%	$14,554,987	35.3%	35.3%
2	$6,386,130	15.5%	32.5%	$9,995,342	24.2%	59.5%
3	$6,262,971	15.2%	47.7%	$2,749,772	6.7%	66.1%
4	$2,889,773	7.0%	54.7%	$2,077,975	5.0%	71.2%
5	$2,077,975	5.0%	59.7%	$1,999,850	4.8%	76.0%
6	$1,275,099	3.1%	62.8%	$1,842,015	4.5%	80.5%
7	$1,045,561	2.5%	65.3%	$1,725,762	4.2%	84.6%
8	$966,712	2.3%	67.7%	$1,363,183	3.3%	87.9%
9	$939,174	2.3%	69.9%	$1,275,099	3.1%	91.0%
10	$888,561	2.2%	72.1%	$972,539	2.4%	93.4%

Lost Opportunity Cost Credits

In 2011, total operating reserve charges increased by only 1.0 percent but the overall level of operating reserve charges remains relatively high. The change in total operating reserve charges included a 51.5 increase in lost opportunity cost credits. Total balancing generator credits for 2011, excluding lost opportunity cost credits, decreased by $49.4 million from 2010. Lost opportunity cost credits increased by $58.5 million.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine is scheduled to operate in the day-ahead market but not requested by PJM in real-time, the unit will receive a credit which covers the day-ahead financial position of the unit plus any balancing spot energy market charge that the unit will have to pay. If a unit generating in real-time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM, the unit will receive a credit for the lost opportunity cost of not being able to produce the desired output.

Table 3-37 shows that 50.3 percent of the generation scheduled in the day-ahead market corresponding to units receiving lost opportunity cost credits was not requested by PJM in real-time. This percentage increased 10.8 percent from 2010.

Table 3-38 shows the distribution by zone of the generation not called in real time. In 2011, 56.0 percent of the day-ahead generation of units receiving lost opportunity cost credits in the Dominion Control Zone was not called in real time.

Daily Distribution of Credits

Figure 3-4 shows the distribution of daily balancing generator credits for 2009 through 2011. The distribution curve for 2011 is similar to the 2010 curve but and starts to diverge towards the upper end of the distribution. The highest level of balancing generator credits paid for one day in 2011 was $13.1 million, compared to $10.7 million in 2010. In 2011, the top 10 days accounted for 19.1 percent share of the total credits, 6.2 percent higher than 2010.

Table 3-34 Daily Operating Reserve Credits HHI: Calendar year 2011

	Daily Operating Reserve Credits HHI							
	Day-Ahead Generators	Day-Ahead Transactions	Synchronous Condensing	Balancing Generators	Balancing Transactions	Lost Opportunity Cost	Canceled Resources	Total Credits
Average	4710	9990	9905	3299	9957	5385	7485	2449
Minimum	1204	9731	7902	1090	5917	872	1236	753
Maximum	10000	10000	10000	9401	10000	10000	10000	7784
Highest market share (One day)	100.0%	100.0%	100.0%	96.9%	100.0%	100.0%	100.0%	88.0%
Highest market share (All days)	51.1%	88.5%	99.3%	24.1%	71.0%	41.5%	47.4%	21.0%
Numbers of Days	365	49	24	365	162	365	206	365
Days with HHI > 1,800	354	49	24	328	162	348	198	255
% of Days with HHI > 1,800	97.0%	100.0%	100.0%	89.9%	100.0%	95.3%	96.1%	69.9%
Days with HHI = 10,000	4	47	22	0	151	6	97	0
% of Days with HHI = 10,000	1.1%	95.9%	91.7%	0.0%	93.2%	1.6%	47.1%	0.0%

Table 3-35 Identification of balancing operating reserve credits received by the top 10 units by category and region

	Credits for Reliability			Credits for Deviations			
Rank	RTO	East	West	RTO	East	West	Total Credits
1	$7,256,380	$0	$0	$20,622,462	$0	$0	$27,878,841
2	$562,133	$0	$0	$666,620	$16,833,134	$0	$18,061,887
3	$3,103,545	$0	$0	$8,117,646	$968,632	$0	$12,189,823
4	$1,417,100	$151,488	$0	$10,303,057	$47,638	$0	$11,919,282
5	$1,076,370	$0	$0	$7,796,324	$0	$0	$8,872,694
6	$1,420,635	$591,704	$0	$5,216,184	$266,382	$267,665	$7,762,569
7	$71,475	$507,544	$0	$45,716	$6,619,603	$0	$7,244,337
8	$72,891	$0	$6,917,112	$114,878	$0	$0	$7,104,881
9	$885,962	$172,175	$0	$3,944,397	$372,504	$0	$5,375,038
10	$139,025	$0	$3,712,715	$298,322	$0	$267,190	$4,417,252
Total	$16,005,513	$1,422,910	$10,629,827	$57,125,606	$25,107,893	$534,855	$110,826,604

Table 3-36 Proportion of the top 10 units receiving balancing operating reserve credits by category and region: Calendar year 2011

	Share of Credits for Reliability			Share of Credits for Deviations			Share of Credits	
Rank	RTO	East	West	RTO	East	West	Reliability	Deviations
1	26.0%	0.0%	0.0%	74.0%	0.0%	0.0%	26.0%	74.0%
2	3.1%	0.0%	0.0%	3.7%	93.2%	0.0%	3.1%	96.9%
3	25.5%	0.0%	0.0%	66.6%	7.9%	0.0%	25.5%	74.5%
4	11.9%	1.3%	0.0%	86.4%	0.4%	0.0%	13.2%	86.8%
5	12.1%	0.0%	0.0%	87.9%	0.0%	0.0%	12.1%	87.9%
6	18.3%	7.6%	0.0%	67.2%	3.4%	3.4%	25.9%	74.1%
7	1.0%	7.0%	0.0%	0.6%	91.4%	0.0%	8.0%	92.0%
8	1.0%	0.0%	97.4%	1.6%	0.0%	0.0%	98.4%	1.6%
9	16.5%	3.2%	0.0%	73.4%	6.9%	0.0%	19.7%	80.3%
10	3.1%	0.0%	84.1%	6.8%	0.0%	6.0%	87.2%	12.8%
Top 10 units	14.4%	1.3%	9.6%	51.5%	22.7%	0.5%	25.3%	74.7%

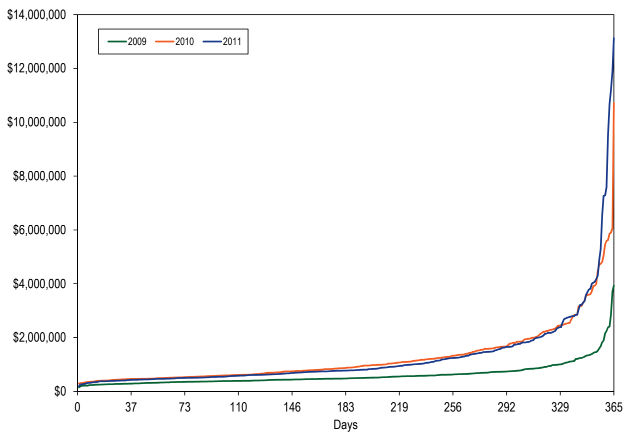
Table 3-37 Reduced / Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits (MWh): Calendar year 2009 through 2011

	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Called in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
2009	4,077,730	1,621,867	28.5%
2010	5,285,833	3,444,165	39.5%
2011	4,648,666	4,713,960	50.3%

Table 3-38 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits by zone (MWh): Calendar year 2011

Zone	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Called in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
AECO	572	61,893	1.3%
AEP - DAY	627,380	368,820	7.8%
AP - DLCO	151,159	399,091	8.5%
ATSI	50,727	246,391	5.2%
BGE - Pepco	60,147	92,658	2.0%
ComEd	245,307	461,294	9.8%
Dominion	2,437,122	2,639,898	56.0%
DPL	6,963	102,265	2.2%
JCPL - PSEG	342,874	118,615	2.5%
Met-Ed - PPL	175,996	79,373	1.7%
PECO	176,081	44,582	0.9%
PENELEC	374,338	99,081	2.1%
RECO	0	0	0.0%
External	0	0	0.0%
Total	4,648,666	4,713,960	100.0%

Figure 3-4 Balancing Generator Credits Daily Distribution: Calendar years 2009 through 2011



Regional Allocation Impact

Regional Credits Allocation Figure 3-5 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules in December 2008. The figure shows the impact of the regional allocation of balancing operating reserve credits during events that only affect a specific region. High east reliability credits during the summer of 2010 were due to transmission maintenance on a 230kV line, while high east deviations credits during the summer of 2011 were the result of high load levels during the peak months.

Figure 3-5 Monthly regional reliability and deviations credits: December 2008 through December 2011[15]

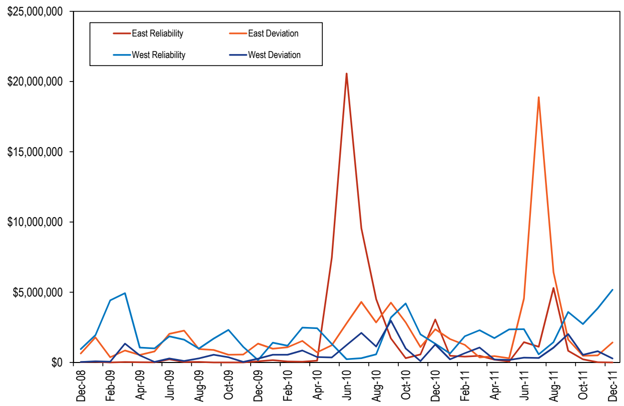
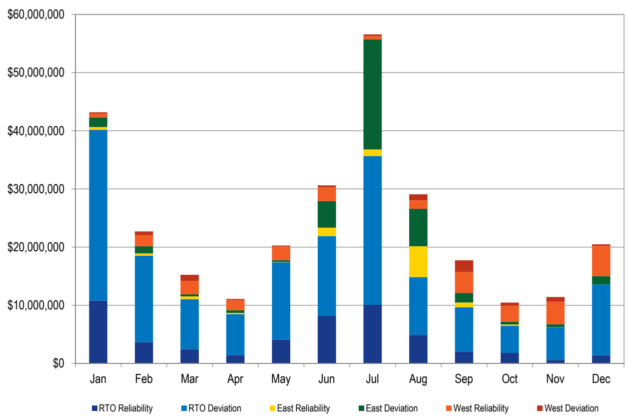


Figure 3-6 Monthly balancing operating reserve categories: Calendar year 2011



One of the purposes of the operating reserve rules implemented on December 1, 2008, was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be

15 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost, canceled resources or resources controlling local transmission constraints.

real-time load and exports. In 2011, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In 2011, $90.7 million of reliability charges were allocated to participants serving real-time load and exports, which would have been charged to deviations under the prior rules.

Eastern reliability credits were a primary reason for the decrease in balancing generator operating reserve charges in 2011. Charges paid by real-time load and real-time exports in the East Region decreased by 78.0 percent in 2011, from $48.2 million to $10.6 million.

Con-Ed – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG.[16] These units are often run out of merit and received substantial balancing operating reserves credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly. Of the total balancing operating reserve credits paid to these units, 75.6 percent was allocated as RTO deviation charges, 20.6 percent as RTO reliability charges and the remaining 3.8 percent was allocated regionally. Table 3-41 shows the impact that the total credits paid to these units had on the balancing operating reserve rates.

AEP Blackstart and Voltage Support Units

Certain units located in the AEP zone are relied on for their blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. Units providing blackstart service under the ALR option could remain running at a minimum level, disconnected from the grid. In 2011 an estimated total of $6.5 million or 33.6 percent of all balancing operating reserve credits paid to ALR capable units was for the purpose of providing blackstart and an estimated total of $7.0 million or 52.1 percent of all balancing operating reserve credits paid to ALR units and units capable of providing voltage support was for the purpose of providing voltage support. The MMU recommends that PJM dispatchers explicitly log the reasons that these units are run out-of-merit to comply with blackstart requirements or voltage support in order to correctly assign the associated charges. Of the total balancing operating reserve credits paid to these units, 83.8 percent was allocated as Western Region reliability charges, 12.3 percent as RTO deviation charges and 4.0 percent as RTO reliability and Western Region deviation charges. Table 3-42 shows the impact that the total credits paid to these units had on the balancing operating reserve rates.

Operating Reserve Transaction Credits

Balancing operating reserve transaction credits are paid to real-time import transactions and interchange transactions under the PEC JOA if the balancing market value does not cover the transactions' real-time offer.[17]

The $22.5 million level of dispatchable transaction credits in December 2010 was unprecedented. Table 3-43 shows that in 2011, the dispatchable transaction credits dropped to $1.3 million.

Emergency Load Response Program Credits Allocation

The cost of emergency load reduction used by PJM to provide relief in the system is allocated to participants' real-time deviations from their net interchange in the Day-Ahead Energy Market. PJM should identify whether such resources are being used for reliability purposes or deviations from the Day-Ahead Energy Market.

Up-to Congestion Transactions

Up-to congestion transactions do not pay balancing operating reserve charges. The MMU calculated the impact on balancing operating reserve rates if up-to congestion transactions paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do.

Table 3-44 shows the impact that including up-to congestion transactions in the allocation of balancing

16 See the *2011 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

17 See the *2011 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" for a description of these transactions.

Table 3-39 Monthly balancing operating reserve categories: Calendar year 2011

Month	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$10,806,714	$477,269	$640,786	$29,352,529	$1,671,868	$221,530
Feb	$3,681,952	$415,538	$1,866,911	$14,822,319	$1,250,992	$661,159
Mar	$2,463,616	$474,514	$2,296,476	$8,597,357	$357,289	$1,059,607
Apr	$1,435,954	$202,956	$1,736,060	$7,055,852	$451,405	$212,437
May	$4,103,637	$65,753	$2,354,336	$13,281,781	$299,705	$179,861
Jun	$8,165,971	$1,447,838	$2,371,314	$13,729,792	$4,548,997	$342,003
Jul	$10,072,493	$1,118,709	$577,816	$25,595,411	$18,882,232	$318,986
Aug	$4,898,914	$5,307,572	$1,446,631	$9,947,911	$6,422,833	$1,054,221
Sep	$2,001,833	$833,334	$3,595,082	$7,650,135	$1,629,589	$2,025,717
Oct	$1,812,773	$227,427	$2,735,378	$4,666,347	$477,293	$541,589
Nov	$599,014	$15,562	$3,854,610	$5,637,319	$507,559	$801,346
Dec	$1,406,230	$0	$5,181,248	$12,178,866	$1,427,650	$283,905
Total	$51,449,101	$10,586,472	$28,656,646	$152,515,621	$37,927,411	$7,702,362

Table 3-40 Charges to real-time load, real-time exports and deviations by region: Calendar year 2009 through 2011

Credit Type	Region	2009	2010	2011	2011 - 2010 Difference	Percentage Difference
Deviations	RTO	$125,850,691	$184,318,710	$152,515,621	($31,803,088)	(17.3%)
	East	$12,904,076	$25,983,926	$37,927,411	$11,943,484	46.0%
	West	$3,968,820	$12,516,876	$7,702,362	($4,814,514)	(38.5%)
	Total	$142,723,586	$222,819,512	$198,145,394	($24,674,118)	(11.1%)
Reliability	RTO	$7,061,503	$43,812,027	$51,449,101	$7,637,073	17.4%
	East	$497,589	$48,187,002	$10,586,472	($37,600,530)	(78.0%)
	West	$23,066,804	$20,692,661	$28,656,646	$7,963,986	38.5%
	Total	$30,625,896	$112,691,690	$90,692,219	($21,999,471)	(19.5%)
Total		$173,349,483	$335,511,201	$288,837,612	($46,673,589)	(13.9%)

Table 3-41 Potential wheeling units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.052	0.068	0.016	29.8%
	East	0.024	0.027	0.003	13.1%
	West	0.078	0.078	0.000	0.0%
Deviation	RTO	0.677	0.946	0.269	39.8%
	East	0.416	0.423	0.008	1.8%
	West	0.104	0.108	0.004	3.6%

Table 3-42 ALR and voltage support units' credits impact on the balancing operating reserve rates ($/MWh)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Units' Credits	Current	($/MWh)	Percentage
Reliability	RTO	0.067	0.068	0.001	1.9%
	East	0.027	0.027	0.000	0.0%
	West	0.004	0.078	0.074	2,017.5%
Deviation	RTO	0.921	0.946	0.025	2.7%
	East	0.423	0.423	0.000	0.0%
	West	0.103	0.108	0.005	4.9%

Table 3-43 Monthly balancing transaction credits: Calendar year 2011

Month	Dispatchable Transaction Credits	JOA Make-Whole Credit	Total Balancing Transaction Credits
Jan	$392,816	$80,423	$473,239
Feb	$330,419	$47,637	$378,056
Mar	$363,835	$58,027	$421,862
Apr	$165,633	$50,183	$215,816
May	$0	$13,365	$13,365
Jun	$142	$19,935	$20,077
Jul	$0	$1,068	$1,068
Aug	$0	$4,774	$4,774
Sep	$0	$40,005	$40,005
Oct	$0	$38,865	$38,865
Nov	$0	$114,037	$114,037
Dec	$0	$43,712	$43,712
Total	$1,252,846	$512,031	$1,764,877

Table 3-44 Up-to Congestion Transactions Impact on the Operating Reserve Rates: Calendar year 2011

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.107	0.086	(0.020)	(19.1%)
RTO Deviations	0.946	0.281	(0.665)	(70.3%)
East Deviations	0.423	0.171	(0.252)	(59.5%)
West Deviations	0.108	0.024	(0.084)	(77.8%)
Lost Opportunity Cost	1.068	0.317	(0.751)	(70.3%)
Canceled Resources	0.056	0.017	(0.039)	(70.3%)

operating reserve charges would have had on 2011 operating reserve rates. For example, the RTO deviations rate would have been reduced $0.6648 per MWh or 70.3 percent. The impact on deviations also means that all deviations rates plus lost opportunity cost and canceled resources rates are affected.

Lost Opportunity Cost Calculation

Lost Opportunity Cost Billing Error

On November 22, 2011, PJM filed a petition with FERC requesting a procedural framework within which to correct settlements of balancing operating reserve lost opportunity cost billings between 2009 and 2011.[18] The tariff provides for the calculation of opportunity cost as LMP less the higher of the price or cost offer.[19] However, the software code included in the Market Settlement Calculation System (MSCS) calculated opportunity cost as LMP less the price offer.[20] As a result, certain participants who regularly included cost offers higher than price offers and received operating reserves credits, received significant overpayments during the relevant period. Likewise, LSEs were overcharged. PJM estimates that it would need to correct its billings as provided in the tariff for an amount of approximately $99.7 million.[21] PJM and the Market Monitor are engaged in discussions with the participants who received most of the overpayments.[22]

Lost Opportunity Cost Eligibility

Under the current rules, CTs and Diesel engines are eligible to receive day-ahead lost opportunity cost if they are scheduled in the Day-Ahead Market but are not called in real time. These unit types need to be called by PJM in the real-time in order to be turned on, even when they have been scheduled in the Day-Ahead Market. PJM has proposed that all units (regardless of their technology) with a lead time (notification plus start-up time) longer than 2 hours be in effect called in real-time when scheduled in the Day-Ahead Market. The result is that PJM is not obligated to call the unit on and there is no obligation to opportunity cost credits if the unit is not called on in real time. This will prevent such units with lead times longer than 2 hours from receiving day-ahead LOC credits unless PJM explicitly directs the unit to not come on line. In 2011, 68.1 percent of all lost opportunity cost credits or $117.4 million were paid to units that were scheduled in the Day-Ahead Market and not called in real-time and had lead times longer than 2 hours.

Unit Parameters: Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers. This issue is currently in discussion in the PJM stakeholder process.

Limits on these parameters will help ensure that capacity resources, paid for in RPM, meet their obligation to make legitimate and competitive offers in the Day-Ahead Market every day.

18 See Petition of PJM Interconnection, L.L.C. for Institution of Proceeding to Determine Proper Billing Adjustments and for Waiver of Tariff, Docket No. ER12-469-000 (December 22, 2011) (December 22nd Petition).

19 OA Schedule 1 § 3.2.3(f) & (f-1).

20 December 22nd Petition at 2–3.

21 Id. at 4; OA Schedule 1 § 15.6.

22 Id. at 8–9.

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]

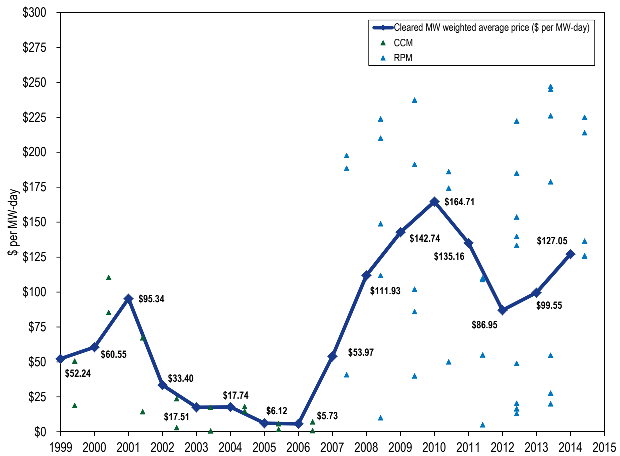


Table 4-23 RPM cost to load: 2011/2012 through 2014/2015 RPM Auctions[89,90,91]

	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.

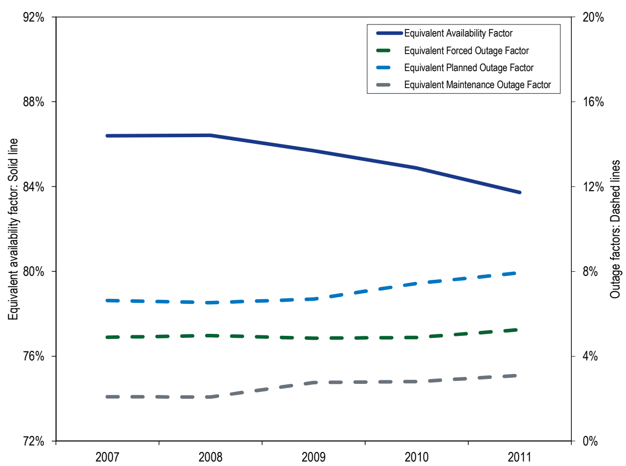
104 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.

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

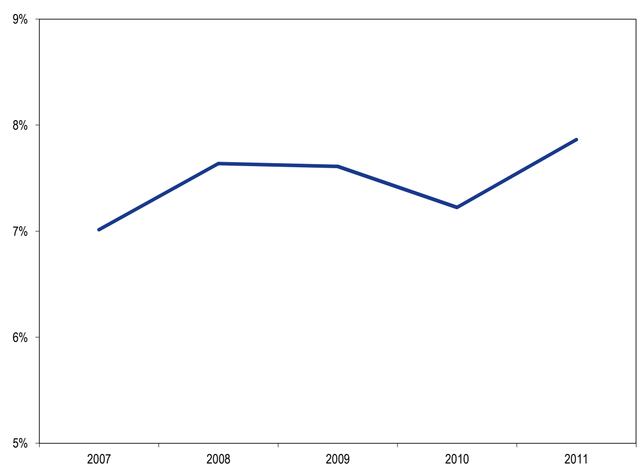


Generator Forced Outage Rates

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.

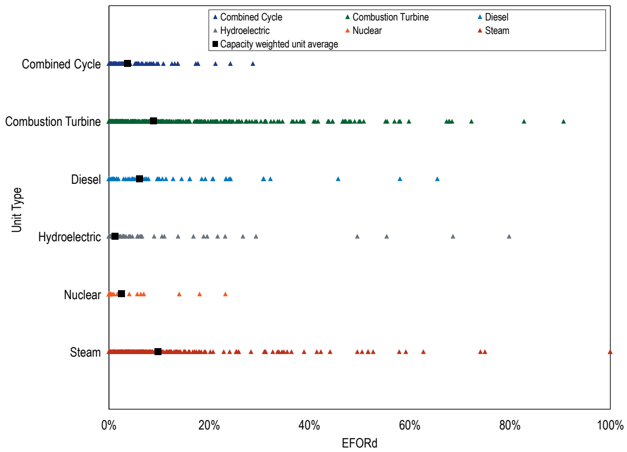
108 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

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

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.

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

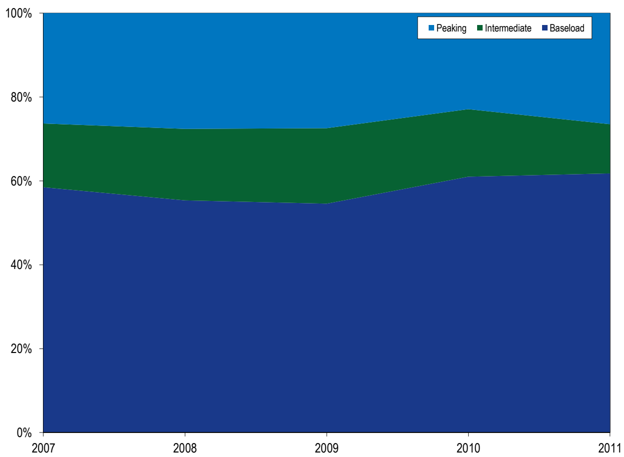
In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[113] Figure 4-5 shows the contribution of unit types to system average EFORd. Total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

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

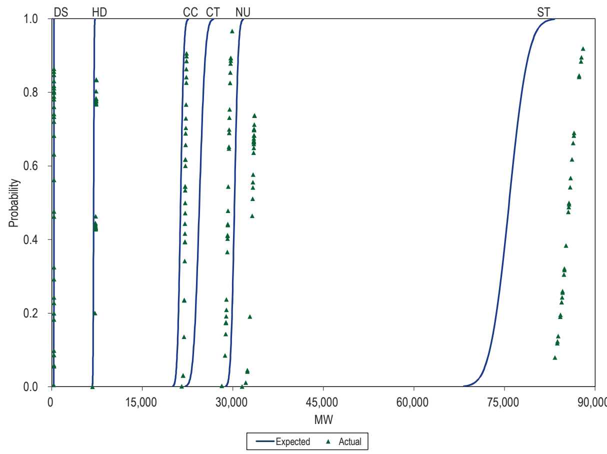
If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within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

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



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

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:

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

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

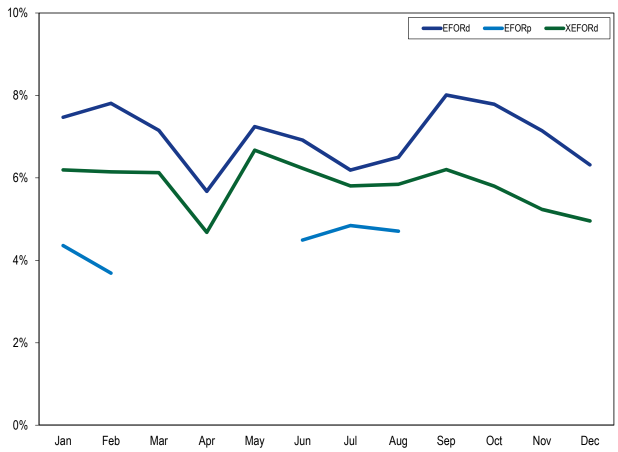
$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

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

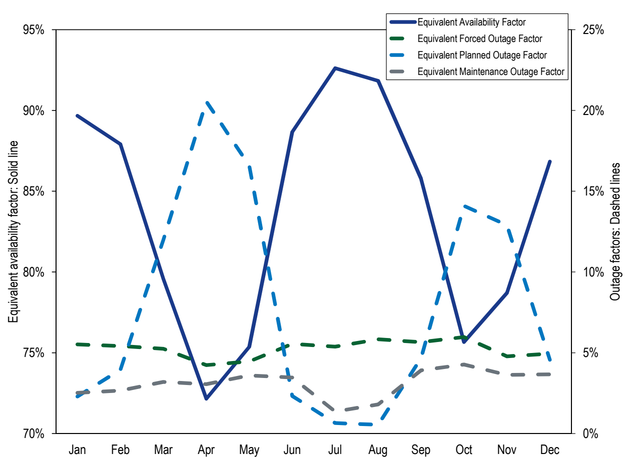
On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7.

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



Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional.

Overview

- **Demand-Side Response Activity.** In calendar year 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 57,288 MWh compared to the same period in 2010, from 74,070 MWh in 2010 to 16,782 MWh in 2011, a 77 percent decrease. Total payments under the Economic Program decreased by $1,080,438, from $3,088,049 in 2010 to $2,007,612 in 2011, a 35 percent decrease.

  Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted compared to the same period in 2010. Participation levels since 2008 have generally been lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for 2011 (July 21, 2011), there were 2,041.5 MW registered in the Economic Load Response Program.

  Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to participants in PJM demand side programs. In 2011, Load Management (LM) Program revenues decreased by $25.2 million or 4.9 percent, from $512 million to $487 million. Through calendar year 2011, Synchronized Reserve credits for demand side resources increased by $4.1 million compared to the same period in 2010, from $5.3 million in 2010 to $9.4 million in 2011.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate. The disconnect created by the fact that CSPs are still permitted to aggregate customers on a zonal basis is being addressed through the stakeholder process. More locational deployment of demand-side resources improves efficiency in a nodal market where demand side resources should be dispatched consistent with transmission constraints.

Conclusions

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP. End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[1] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However,

1 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[2] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average LMP. PJM's proposed PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[3]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental, locational costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption.

Detailed Recommendations

- The MMU recommends elimination of the Limited and Extended Summer Demand Response products from the capacity market. All products competing in the capacity market should be required to be available to perform when called for every hour of the year.

2 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

3 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

Table 5-1 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on LMP less generation and transmission component of retail rate. Energy payment for hours of voluntary curtailment.

The MMU recommends that PJM continue to implement subzonal dispatch for Demand Response products and develop a plan to implement nodal dispatch for all demand resources.

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.
- The MMU recommends that there be improvement in measurement and verification methods implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. PJM has implemented or plans to implement changes to the CBL calculation that should improve measurement and verification for many customers.
  - The MMU recommends that the testing program be modified to require verification of test methods and results. Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no physical or technical oversight or verification, although EDC's can request additional test data from the CSP. In order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently received by PJM. The MMU recommends that all available metered load data should be submitted to PJM and the MMU in order to verify accurate testing and measurement of customer loads.
  - The MMU recommends that any baseline approach that attempts to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants, and be limited to the days closest to the event.
  - The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements.

PJM Demand Side Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 5-1 provides an overview of the key features of PJM load response programs.[4]

4 For more detail on the historical development of PJM Load Response Programs see the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml>.

Demand Side in the Energy Market: Economic Load Response

In the Economic Load Response Program (ELRP, or the Economic Program), all hours are eligible and all participation is voluntary. The ELRP Program is designed to facilitate the participation of demand response in PJM Energy Markets. Participation in the ELRP takes three forms: submitting a sell offer into the Day-Ahead Market that clears; submitting a sell offer into the Real-Time Market that is dispatched; and self scheduling load reductions while providing notification to PJM. In the first two methods, a load reduction offer is submitted to PJM through the eMkt system specifying the minimum reduction price, including any associated shutdown costs, and the minimum duration of the load reduction.

The fundamental purpose of PJM's Economic Load Response Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly nodal LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[5]

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the wholesale market), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. Accordingly, the appropriate compensation for load reductions in the Economic Program is LMP less the generation component of the applicable retail rate per MWh. Nonetheless, it would be a reasonable approach to the policy objective of increasing demand side participation to pay the full LMP to retail customers who pay flat retail rates, for accurately measured load reductions. But it would not be reasonable to pay full LMP to customers who already pay LMP directly rather than a flat retail rate. In that case, the market failure that the program is designed to address does not exist. Payment of full LMP to customers already paying LMP would be paying the customer twice for the same action.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentives and regulatory structures faced by both LSEs and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market. However, implementation of the Economic Load-Response Program changes on April 1, 2012, will change the nature of the program and may cause additional concerns.

Economic Incentive Payments: Order No. 745

On March 15, 2011, the Commission issued Order No. 745, in which the Commission ordered RTOs and ISOs to pay demand resources that are capable of balancing supply and demand full LMP.[6] In this order, demand resources that are cost-effective as determined by a "Net Benefits Test" (NBT) will be eligible to receive the full LMP rather than LMP less the generation and transmission charges. This approach recognizes that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. Each RTO and ISO was directed to develop a mechanism that would determine the price level at which the dispatch of demand resources would be cost effective.

5 This does not mean that every retail customer should be required to pay the real-time nodal LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were required to pay the real-time nodal LMP as a default. That risk could be hedged via a contract with an intermediary. The transition to full nodal pricing from average zonal LMP should be implemented gradually because it can be expected to have significant impacts on some customers.

6 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

By order issued December 15, 2011, the Commission conditionally accepted PJM's compliance filing with Order No. 745.[7] The Commission directed PJM to continue to pay LMP less generation and transmission when a demand response resource is not cost-effective under the NBT.[8] The Commission also directed PJM to provide guidelines in its tariff governing "PJM's unilateral right to set a CBL when a variable load and PJM cannot reach an agreement."[9] The Commission further directed that PJM propose "an alternative data submission method for the minority of residential and small commercial participants who may have trouble meeting the data requirements."[10] Finally, the Commission ordered PJM to provide for the allocation of costs to areas where the load-weighted average LMP equals or exceeds the price determined under the NBT.[11]

The December 15th Order accepted PJM's requirement that demand resources must be dispatchable by PJM operators, although it did not include a must offer requirement for demand resources.[12] Self-scheduled resources will be ineligible to set LMP, as per their inability to offer flexibility to PJM dispatch. However, demand resources will be able to change offers up to three hours before the operating hour, giving three hour notice to PJM dispatchers in order to handle these resources.

The December 15th Order also approved PJM's clarification, as the Commission stated it, "that meter data from an on-site generator may be used as evidence of a load reduction only to the extent the on-site generator is operated to facilitate its demand reduction."[13] The December 15th Order approved setting the NBT on the basis of a single monthly price for PJM as a whole.[14]

This approach to compensating demand response, effective April 1, 2012, may increase participation in the Economic Load Response Program. This change will also allow double compensation for entities already paying LMP, as these entities will now receive the LMP in addition to the avoided cost of paying that LMP.[15]

7 137 FERC ¶ 61,216.
8 *Id.* at P 16.
9 *Id.* at P 63.
10 *Id.* at P 67.
11 *Id.* at P 78.
12 *Id.* at PP 31–35.
13 *Id.* at P 90.
14 *Id.* at P 43.
15 Comments of the Independent Market Monitor for PJM, Docket No. RM10-17-000 (May 13, 2010), at 2.

Order No. 745 treats demand resources differently than generation resources on several dimensions. Demand resources will not be subject to a must-offer requirement in the Day-Ahead market. Demand resources will be able to alter their schedule up to three hours before the operating hour, including the ability to withdraw the offer to curtail. Behind-the-meter resources will also have a substantial advantage compared to metered generation resources, in that they will have the ability to not offer, and not have to comply with the requirements imposed by PJM rules on metered generation resources.

The NBT uses a single monthly price for PJM. The NBT price threshold will not reflect the price separation in the Real-Time and Day-Ahead markets that results from binding transmission constraints or hourly fluctuations in LMP. The Commission directed PJM to study the inclusion of the NBT in its dispatch algorithm, but this will not be implemented as of April 1, 2012.

Demand Side in the Capacity Market: Emergency Load Response

Load Management generally refers to the integration of load response resources into RPM and thus encompasses both Emergency Load Response Options pertaining to capacity: Full and Capacity Only. In the 2011/2012 delivery year, all participants in the Emergency Program were capacity resources, integrated into RPM through the Load Management Program.

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Load Management (LM) Program was introduced as the mechanism for Emergency Program customers and other DR providers to participate in RPM. Customers in the Emergency-Full and Emergency-Capacity Only options of the Emergency Program are committed capacity resources, which receive RPM capacity payments and which are subject to RPM penalties for noncompliance during emergency events. Emergency-Full customers are also eligible for energy payments for reductions during emergency events.[16]

The Load Management (LM) program was, from its inception in June 2007, comprised of two types of resources: Interruptible Load for Reliability (ILR)

16 For additional information on RPM provisions for customers in the Emergency Load Response Program, see PJM, "Manual 18: PJM Capacity Market," Revision 10 (June 1, 2010).

resources and Demand Resources (DR).[17] Customers offering DR resources submit a capacity sell bid into an RPM Auction and are paid the clearing price. Interruptible load for reliability (ILR) resources must be certified at least three months prior to the delivery year and are paid the final zonal ILR price. The ILR option was eliminated on March 26, 2009 for the delivery year beginning June 1, 2012.[18] A DR resource must be registered in the Emergency Full option or the Capacity Only option.

The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year for a maximum duration of six hours per interruption represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

In the Emergency Load Response Program, only hours in which PJM has declared an Emergency Event are eligible. Participation may be voluntary or mandatory, and payments may include energy payments, capacity payments or both.

There are three options for Emergency Load Response registration and participation: energy only; capacity only; and capacity plus energy (full emergency option).

Energy Only

In the Energy Only option, participants submit a minimum dispatch price for load reductions during emergency events, which include shutdown costs and a minimum duration. All participation is voluntary. This option of the Emergency Program is similar to the Economic Program in that it provides only energy payments and all participation is voluntary. However, compensation differs significantly between the two programs as Energy Only participants in the Emergency Program receive the greater of LMP or the value of the submitted minimum dispatch price, including shutdown, for the duration of the emergency reduction.

Capacity Only

In the Capacity Only Program option, participants are considered a capacity resource, and are obligated to reduce load during emergency events. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge. The participant receives capacity payments, however, no energy offers are submitted and no energy payments during emergency events are applicable. This option exists to accommodate registrations in which the Curtailment Service Provider may only provide capacity related services or situations in which the customer is participating in the Economic Program or in Ancillary Service markets when managed by another CSP.

Capacity plus Energy (Full Emergency Option)

Similar to the Energy Only option, participants in the Full Emergency option submit minimum dispatch prices associated with reductions during emergency events. In addition, they are considered committed capacity resources and receive capacity payments. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge.

Minimum Dispatch Price

During an emergency event, participants registered in the Full Emergency option and the Emergency Energy Only option will be paid the higher of the submitted minimum strike price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. For the 2011/2012 delivery year, approximately 73 percent of registered sites representing 64 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh.

17 As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.
18 126 FERC ¶ 61,275 (2009).

There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP. Compensation in the Emergency Program should be directly aligned with the RPM market clearing price. The appropriate energy market price signal for load reduction in any hour is the hourly LMP. This means that the appropriate compensation in any PJM Program is the LMP less the generation component of a fixed retail rate, which is already made available through participation in the Economic Program. There is no need for energy payments through the Emergency Program. The current design of the Emergency Program incents resources to seek overcompensation through Emergency Energy payments equal to the greater of LMP or a submitted minimum dispatch price, which, in most cases is set at $1,000/MWh.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment to customers on a flat retail rate in excess of the real-time LMP net of generation costs results in a subsidy, subject to the caveat that such a subsidy may be an appropriate policy for a limited transition period.[19]

In the Economic Program, customers also have the opportunity to submit a minimum price at which they will curtail. However, customers in the Economic Program will be dispatched economically and paid the real-time LMP less the generation and transmission component of their fixed retail rate only if they are dispatched.[20] Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Double Counting

PJM procures capacity for load-serving entities (LSEs) through the Reliability Pricing Model (RPM). LSEs use customers' Peak Load Contribution or PLC to allocate capacity obligations and the cost of capacity among their customers.[21] Use of PLC as a basis for allocating capacity obligations and capacity costs predates the establishment of PJM's current capacity market, the Reliability Pricing Model (RPM); emergency demand response programs; and even the organized wholesale electricity markets. Large, sophisticated customers have also managed their PLCs for many years to achieve a lower PLC and, as a result, reduce their obligation to purchase capacity and reduce their payments for capacity. (Such customers are termed self managing.)

Prior to the introduction of demand response programs it was reasonable to assume that customers managing their PLC would continue to manage their PLC going forward in order to continue to reduce their obligation to purchase capacity. It was not deemed necessary to formalize a managed PLC as an obligation to reduce customer load during times of system peak load because continued management of the PLC resulted in reduced loads on high load days. Prior to the introduction of RPM and DR programs, the incentives to manage PLC

19 Energy Only participants are also paid the higher of the real-time LMP and the submitted minimum dispatch price. However, there are currently no participants registered under this option.

20 OA Schedule 1 § 3.3A.4(a).

21 The peak load contribution (PLC) is measured by a customer's consumption during the five coincident peak hours in the prior year.

and the resultant actions were consistent with economic signals and generally resulted in a match between reduced peak loads and reduced capacity payments. PLC management was and continues to be, in effect, a market based demand side management program.

The PJM Emergency Demand Response program provides customers an alternative to managing PLC as a way to reduce the obligation to purchase capacity. A customer can register as a capacity resource in the Program and receive credit for the amount of capacity it is willing to curtail in a given delivery year. The amount that can be nominated in the Program is limited to the customer's current PLC.[22] In return for not paying for the capacity associated with that curtailed load, the customer agrees to reduce load by that amount when customers who are paying for the capacity need it. A party that manages PLC avoids paying for capacity, but also assumes responsibility for determining when to curtail. Participants in PJM's Emergency Load Response Program curtail when called by PJM.

Self managed customers who elect the Guaranteed Load Drop (GLD) measurement and verification option will show substantial apparent measured over compliance during an Emergency LM event. The over compliance results from the fact that the GLD option measures compliance as the reduction in real time consumption from a baseline established by actual recent consumption. This baseline consumption reflects full load rather than managed load and thus will reflect consumption above a customer's PLC. The reduction observed for compliance will show the full reduction capability of the customer, including the load that the customer already reduced to manage its PLC. The measured reduction may be significantly higher than the amount nominated in the LM Program, which may not exceed the PLC. This results in double counting of the savings.

Double counting takes two forms. Double counting may exist at an individual customer level or at a CSP portfolio level.

At the level of an individual customer, when a customer that previously managed its PLC shows measured over compliance based on GLD, the result is a disconnect between the amount of capacity that a customer did not pay for based on its availability to be curtailed, and the amount offered by the customer in the delivery year as a reduction. In the same delivery year, due to the lag between PLC management and associated savings, the customer pays for capacity equal to the lower PLC and, if consumption is greater than PLC, may request and receive credit for not using capacity that was not paid for under one interpretation of the rules, which was accepted in 2011. That credit constitutes double counting. This double counting at an individual customer level occurs when the PJM rules limiting nominations to the PLC are interpreted as permitting a reduction from peak load by the amount of the PLC rather than permitting only a reduction below the PLC level. Only the second is a logical interpretation and consistent with the fundamental economics and appropriate incentives.

At the portfolio level, the double counting issue is exacerbated when customers with managed PLCs are included in a portfolio managed by a Curtailment Service Provider (CSP). Although a GLD customer that has managed its PLC cannot claim a capacity benefit greater than its nomination, the netting rules permit a CSP to use measured over compliance from such customers in its portfolio to offset underperforming resources in its portfolio, under one interpretation of the rules. Netting is not the issue. The use of apparent overcompliance as the basis for netting creates the double counting issue at the portfolio level.

It is double counting because the self managing customer is incurring a capacity obligation only equal to its PLC and therefore paying for capacity only equal to its PLC, but the CSP is being paid for reducing load from peak to PLC. The customer, through the CSP, is selling back to PJM capacity that it did not purchase.

Netting is appropriate when it recognizes additional reductions below PLC in excess of nominated levels. However, the rules should explicitly prohibit CSPs from crediting apparent over compliance against underperforming parts of its portfolio when such over compliance is attributable to reductions which occur at MW levels greater than PLC.

The data on customer compliance show that some LM participants that selected the GLD method for measurement and verification claimed load reductions in excess of their PLCs, and that the load reductions

22 OATT Attachment DD-1 § J.

associated with these participants account for a significant portion of overall compliance. Table 5-17 shows that, in 2011, of the total load reductions submitted for the July 22 Load Management event by customers using the GLD measurement and verification approach, 51 percent of the MW of submitted load reductions were in excess of customers' PLCs and that 29 percent of such MW were in excess of 150 percent of customers' PLCs. This is strong evidence that double counting remained a significant issue in 2011.

The issue is further complicated by the disconnect between the load reduction value used to measure compliance and the addback process, which is part of determining the customer's capacity obligation for the following year. When an LM customer, which does not directly manage PLC, reduces load during an Emergency event, that reduction will generally reduce the customer's PLC and therefore its obligation to purchase and pay for capacity in the following year.[23] If the customer appropriately participates in the LM program, it is paid for its reductions from its PLC. The addback means that the reduction is added back to the customer's load in order to ensure that its peak load and therefore PLC are correctly calculated for the next year. The addback prevents the PLC for such a customer from being inappropriately reduced as a result of participation in the LM program. The addback ensures that in the following year, the customer's load obligation reflects unmanaged levels and thus the customer will be able to nominate up to its full reduction in that year. The problem arises because the addback is limited to the amount nominated in the current delivery year. Thus, when a customer shows measured overcompliance in excess of its nomination, the addback is limited to the nomination. As a result, the customer's PLC is understated for the next year, which means that the customer's capacity obligation is understated and creates the potential for an additional double counting issue for the customer.[24]

By order issued November 4, 2011, the Commission conditionally accepted revisions to the tariff proposed by PJM to clarify the rules and correct the double counting issue.[25] The clarified provisions specify that a GLD customer's load drop would "only be recognized if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution."

The November 4th order directed PJM to submit a compliance filing that allows for an interim mitigation measure that will apply to the 2012/2013 through 2014/15 Delivery Years and protect the reasonable reliance expectations of DR suppliers through that period.[26] On January 4, 2012, PJM filed a compliance filing to the Commission. This filing clarified issues regarding aggregation and compensation for reductions below PLC, as well as dealing with the "reasonable reliance expectations" of DR suppliers for Delivery Years in which BRAs have been held. As interim mitigation measures, PJM offered two possibilities to deal with "reasonable reliance expectations."

To deal with other possible reliance expectations, "PJM further proposes to allow any qualified DR provider to demonstrate that it has unavoidable contractual obligations to end-use customers during the transition delivery years which the purchase of replacement capacity in the Incremental Auctions will not mitigate." Specifically, this provision would deal with any contractual commitments for CSPs that were signed before April 7, 2011, the date of PJM's original filing.

In an order issued February 24, 2012, the Commission conditionally accepted PJM's compliance filing.[27] While the Commission accepted the majority of PJM's filing, PJM was directed to explain how CSPs will be compensated for unavoidable losses resulting from contracts signed prior to April 7, 2011. PJM's compliance filing is due by March 10, 2012.

New Demand Response Capacity Products

On December 2, 2010, PJM proposed, and by order issued January 31, 2011, the Commission approved, an unlimited demand-side capacity product, which it terms "Annual DR."[28] PJM also proposed and the Commission accepted the continued use of "Limited DR" and another new product, "Extended Summer DR." Limited DR simply continues the current limited product. Extended Summer DR includes more obligations than Limited DR but fewer

23 If the event coincides with one of the five coincident peak hours.

24 For more information including a detailed example, see the IMM/PJM joint statement regarding double counting: <http://www.MonitoringAnalytics.com/reports/Market_Messages/Messages/PJM_IMM_Joint_Statement_DR_Double_Counting_20110204.pdf>.

25 137 FERC ¶ 61,108 at P 64 (2011).

26 *Id.* at P 81.

27 138 FERC ¶ 61,138 (2012).

28 PJM filing in Docket No. ER11-2288-000; 134 FERC ¶ 61,066 (2011).

than Annual DR. PJM provided testimony explaining how Limited DR is flawed and poses an increasing reliability risk, but did not propose to eliminate it.[29]

Limited products are inferior to unlimited products and permitting the limited products to replace the unlimited demand side product or the unlimited generation product distorts capacity market outcomes. A single unlimited demand-side capacity product is all that the PJM capacity market needs, and such a product could provide maximum flexibility for participants whatever their particular operational characteristics or preexisting investment. Given that Curtailment Service Providers (CSPs) can and do aggregate participants into portfolios eligible to serve as DR, the market design can accommodate participation by any customer. CSPs are better situated than PJM to play the role of aggregator, and providing CSPs with an incentive to do so will sustain the growth of demand-side participation in PJM markets.

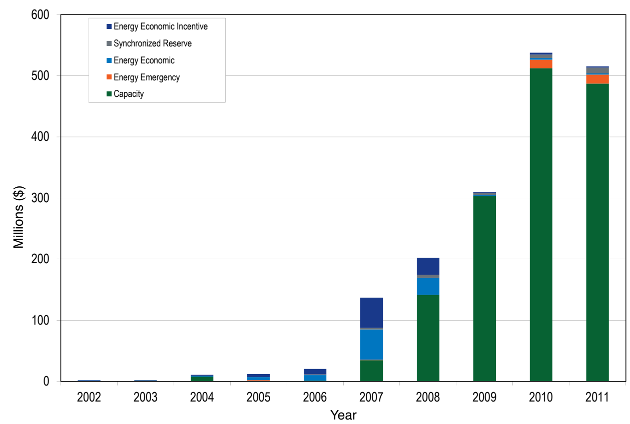
Participation in Demand Side Programs

In 2011, in the Economic Program, participation became more concentrated by site compared to 2001. There were fewer settlements submitted and active registrations in 2011 compared to 2010, and settled MWh and credits decreased. The number of sites registered decreased more significantly than the level of registered MW.

In 2011, LM Program participation increased compared to 2010. For the 2011/2012 delivery year, there were 11,522.7 MW registered in the LM Program, compared to 9,052.4 MW registered in the 2010/2011 delivery year.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2011. Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to demand side participants. In 2011, Economic Program revenue decreased by $1.1 million or 35.0 percent, from $3.1 million to $2.0 million. Capacity revenue decreased by $25 million or 8.3 percent, from $512 million to $487 million. Synchronized Reserve credits increased by $4.1 million, from approximately $5.3 million to $9.4 million from 2010 to 2011. Emergency energy payments are made to resources through the Emergency Program for reductions during PJM-declared Load Management Events. In 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues, and in 2011, there were three Load Management event-days, resulting in $14.6 million in emergency energy revenues, an increase of 6.3 percent.

Figure 5-1 Demand Response revenue by market: Calendar years 2002 through 2011



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for calendar years 2002 through 2011.[30] On July 21, 2011, there were 2,041.8 MW registered in the Economic Program compared to the 1,725.7 MW on July 6, 2010, an 18.3 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 5-3 shows registered sites and MW for the last day of each month for the period calendar years 2008 through 2011.[31] Registered MW declined in June but increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

29 PJM filing in Docket No. ER11-2288-000, Attachments A (Affidavit of Thomas A. Falin on Behalf of PJM Interconnection, L.L.C.) & B (Affidavit of Michael E. Bryson on Behalf of PJM Interconnection, L.L.C.).(December 2, 2011).

30 Table 5-2 and Table 5-3 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

31 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

Table 5-2 Economic Program registration on peak load days: Calendar years 2002 to 2011

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8

Table 5-3 Economic Program registrations on the last day of the month: 2008 through 2011

	2008		2009		2010		2011	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,609	2,432
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,435
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,612	2,519
Apr	5,016	3,197	2,582	3,242	1,849	2,587	1,611	2,534
May	5,069	3,588	1,250	2,860	1,875	2,819	1,687	3,166
Jun	3,112	3,014	1,265	2,461	813	1,608	1,143	1,912
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,987	2,194
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,962	2,183
Oct	4,846	3,266	1,875	2,730	1,606	2,444	1,954	2,179
Nov	4,851	3,271	1,874	2,730	1,605	2,444	1,954	2,179
Dec	4,851	3,290	1,853	2,627	1,598	2,439	1,992	2,259
Avg.	4,727	3,185	2,508	2,852	1,608	2,435	1,696	2,338

Table 5-4 shows the zonal distribution of capability in the Economic Program on July 21, 2011. The PECO Control Zone includes 310 sites and 142.2 MW, 18 percent of sites and 7 percent of registered MW in the Economic Program. The BGE Control Zone includes 59 sites and 588.7 MW, 3.5 percent of sites and 29 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: July 21, 2011[32]

	Registrations	Sites	MW
AECO	30	33	15.2
AEP	53	104	102.8
AP	132	211	102.3
ATSI	6	6	75.5
BGE	50	59	588.7
ComEd	72	100	92.1
DAY	6	16	7.9
DLCO	33	38	59.7
Dominion	89	93	197.1
DPL	33	39	63.4
JCPL	25	33	120.8
Met-Ed	72	80	84.5
PECO	249	310	142.2
PENELEC	138	169	103.4
Pepco	18	22	14.6
PPL	140	223	225.6
PSEG	90	152	45.8
RECO	1	1	0.3
Total	1,237	1,689	2,041.8

32 The second column of Table 5-4 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

Total Payments in Table 5-5 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[33]

Table 5-5 Performance of PJM Economic Program participants without incentive payments: Calendar years 2002 through 2011

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	74,070	$3,088,049	$42	42.9
2011	16,782	$2,007,612	$120	8.2

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through 2010. Economic Program credits declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[34] Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009.[35] In 2011, credits were down compared to 2010, except the months of May and June 2011.

Figure 5-2 Economic Program payments by month: Calendar years 2007[36] through 2011

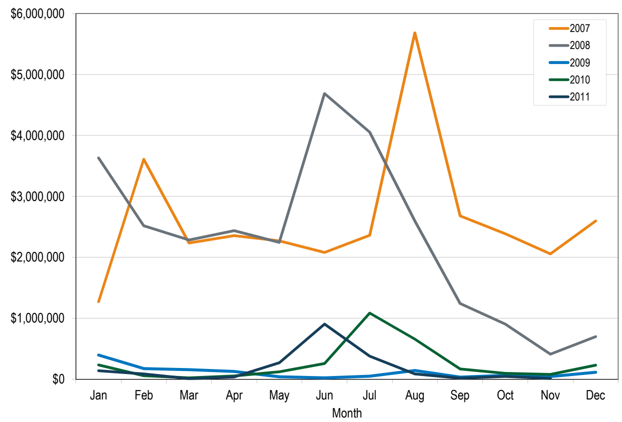


Table 5-6 shows 2011 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 16,782 and the total payment amount was $2,007,612.[37] Overall, approximately 98.6 percent of the MWh reductions, 99.6 percent of payments and 98.7 percent of curtailed hours resulted from the real-time option of the Economic Program. Approximately 1.4 percent of the MWh reductions, 0.4 percent of payments and 1.2 percent of curtailed hours resulted from the day-ahead option. The Dominion Control Zone accounted for $1,062,900 or 53 percent of all Economic Program credits, associated with 11,330.1 or 68 percent of total program MWh reductions.

Table 5-7 shows total settlements submitted by month for calendar years 2007 through 2011. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady

33 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

34 December credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

35 The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008.

36 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 5-2 do not include these incentive payments.

37 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

Table 5-6 PJM Economic Program participation by zone: Calendar year 2010 and 2011

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$5,026	$0	(100%)	86.7	0.0	(100%)
AEP	$56	$24,279	43,293%	7.0	310.0	4,315%
AP	$130,576	$17,988	(86%)	4,459.9	372.2	(92%)
ATSI	$0	$1,829	NA	0.0	19.4	NA
BGE	$445,908	$730,278	64%	3,679.3	2,294.5	(38%)
ComEd	$39,894	$2,420	(94%)	2,298.1	197.4	(91%)
DAY	$1,173	$13,435	1,046%	11.2	18.8	68%
DLCO	$0	$534	NA	0.0	12.9	NA
Dominion	$1,598,117	$1,062,900	(33%)	29,103.1	11,330.1	(61%)
DPL	$248	$59	(76%)	0.9	0.4	(63%)
JCPL	$20,539	$1,075	(95%)	235.5	3.3	(99%)
Met-Ed	$1,359	$17,429	1,182%	32.7	183.9	463%
PECO	$824,400	$78,346	(90%)	33,493.1	1,698.2	(95%)
PENELEC	$918	$3,376	268%	42.5	80.8	90%
Pepco	$3,106	$2,637	(15%)	58.2	38.0	(35%)
PPL	$15,249	$46,041	202%	499.6	188.1	(62%)
PSEG	$1,458	$4,986	242%	61.5	33.9	(45%)
RECO	$24	$0	(100%)	0.4	0.0	(100%)
Total	$3,088,049	$2,007,612	(35%)	74,069.6	16,781.7	(77%)

growth. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009. December of 2011 showed the lowest level of settlements in the five year period, and 2011 overall showed a substantial decrease in the number of settlements submitted compared to previous years.

Table 5-7 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2011

Month	2007	2008	2009	2010	2011
Jan	937	2,916	1,264	1,415	562
Feb	1,170	2,811	654	546	148
Mar	1,255	2,818	574	411	82
Apr	1,540	3,406	337	338	102
May	1,649	3,336	918	673	298
Jun	1,856	3,184	2,727	1,221	743
Jul	2,534	3,339	2,879	3,007	1,411
Aug	3,962	3,848	3,760	2,158	790
Sep	3,388	3,264	2,570	660	294
Oct	3,508	1,977	2,361	699	66
Nov	2,842	1,105	2,321	672	51
Dec	2,675	986	1,240	894	40
Total	26,423	32,990	21,605	12,694	4,587

Table 5-8 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through 2011. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. In 2011, monthly customers appear to follow seasonal trends, high in the summer period and lower in shoulder months, however, the number of active customers in calendar year 2011 increased 172, or 39 percent, over calendar year 2010.

Table 5-9 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2011. The period from hour ending 0800 EPT to 2300 EPT accounts for 94 percent of MWh reductions and 96 percent of credits.

Table 5-10 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred at all price levels. Approximately 40 percent of MWh reductions and 82 percent of program credits are associated with hours when the applicable zonal LMP was greater than or equal to $150.

Table 5-8 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2011

	2008		2009		2010		2011	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	162	5	40
Feb	13	243	12	129	9	92	6	29
Mar	11	216	11	149	7	124	3	15
Apr	12	208	9	76	5	77	3	15
May	12	233	9	201	6	140	6	144
Jun	17	317	20	231	11	152	10	304
Jul	16	295	21	183	18	243	15	214
Aug	17	306	15	400	14	302	14	186
Sep	17	312	11	181	11	97	7	47
Oct	13	226	11	93	8	37	3	9
Nov	14	208	9	143	7	40	3	13
Dec	13	193	10	160	7	46	5	12
Total Distinct Active	24	522	25	747	24	438	20	610

Table 5-9 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2011

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	6	0.03%	6	0.03%	$105	0.01%	$105	0.01%
2	6	0.04%	12	0.07%	$193	0.01%	$298	0.01%
3	12	0.07%	24	0.14%	$619	0.03%	$917	0.05%
4	4	0.02%	28	0.17%	$61	0.00%	$978	0.05%
5	8	0.05%	36	0.22%	$51	0.00%	$1,028	0.05%
6	36	0.21%	72	0.43%	$725	0.04%	$1,754	0.09%
7	956	5.69%	1,028	6.12%	$71,402	3.56%	$73,156	3.64%
8	1,340	7.98%	2,367	14.11%	$124,197	6.19%	$197,353	9.83%
9	570	3.40%	2,937	17.50%	$37,435	1.86%	$234,788	11.69%
10	191	1.14%	3,128	18.64%	$9,052	0.45%	$243,840	12.15%
11	169	1.01%	3,297	19.65%	$4,688	0.23%	$248,529	12.38%
12	260	1.55%	3,557	21.20%	$12,390	0.62%	$260,919	13.00%
13	428	2.55%	3,985	23.75%	$33,834	1.69%	$294,753	14.68%
14	678	4.04%	4,663	27.78%	$69,954	3.48%	$364,707	18.17%
15	1,809	10.78%	6,471	38.56%	$334,304	16.65%	$699,012	34.82%
16	2,482	14.79%	8,953	53.35%	$404,561	20.15%	$1,103,573	54.97%
17	2,972	17.71%	11,925	71.06%	$449,552	22.39%	$1,553,125	77.36%
18	2,593	15.45%	14,519	86.52%	$323,419	16.11%	$1,876,543	93.47%
19	1,448	8.63%	15,966	95.14%	$101,101	5.04%	$1,977,645	98.51%
20	507	3.02%	16,473	98.16%	$19,977	1.00%	$1,997,622	99.50%
21	167	1.00%	16,640	99.16%	$5,560	0.28%	$2,003,182	99.78%
22	72	0.43%	16,712	99.58%	$4,051	0.20%	$2,007,233	99.98%
23	49	0.29%	16,761	99.88%	$323	0.02%	$2,007,555	100.00%
24	21	0.12%	16,782	100.00%	$56	0.00%	$2,007,612	100.00%

Table 5-10 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2011

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	18	0.11%	18	0.11%	$508	0.03%	$508	0.03%
$25 to $50	2,028	12.09%	2,047	12.19%	$10,230	0.51%	$10,738	0.53%
$50 to $75	3,208	19.12%	5,255	31.31%	$57,601	2.87%	$68,339	3.40%
$75 to $100	1,775	10.57%	7,029	41.89%	$71,362	3.55%	$139,701	6.96%
$100 to $125	1,605	9.56%	8,634	51.45%	$99,603	4.96%	$239,304	11.92%
$125 to $150	1,376	8.20%	10,010	59.65%	$122,436	6.10%	$361,741	18.02%
$150 to $200	2,040	12.16%	12,050	71.81%	$248,723	12.39%	$610,464	30.41%
$200 to $250	1,262	7.52%	13,313	79.33%	$210,393	10.48%	$820,857	40.89%
$250 to $300	962	5.73%	14,274	85.06%	$208,525	10.39%	$1,029,382	51.27%
> $300	2,507	14.94%	16,782	100.00%	$978,230	48.73%	$2,007,612	100.00%

Emergency Program

The zonal distribution of DSR capability in the Emergency Program option is shown in Table 5-11 by program option. On July 21, 2011, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program. There were 10,132 sites accounting for 10,334.3 MW registered in the Emergency Full option and 819 sites accounting for 1,188.4 MW registered in Emergency Capacity Only option. The ComEd Control Zone showed the highest number of registered sites in Emergency-Full option at 1,178 or 12 percent, while the AEP Control Zone showed the highest MW capability with 1,623.1 MW registered, or 16 percent of MW registered in the option. The ComEd Control Zone showed the highest participation in the Capacity Only option of the Emergency Program with 496 sites, or 61 percent of total sites, and 479.6 MW, or 40 percent of total MW registered in the option. Total peak-load day registrations in the Emergency Program increased by 39 percent, from 7,881 in 2010 to 10,951 in 2011, and total peak day registered MW increased by 27 percent, from 9,052.4 MW in 2010 to 11,522.7 in 2011.

Table 5-11 Registered sites and MW in the Emergency Program[38] (By zone and option): July 22, 2011

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	173	79.6	2	12.7
AEP	0	0.0	1,028	1,623.1	79	384.4
APS	0	0.0	952	896.5	14	23.0
ATSI	0	0.0	487	1,238.4	0	0.0
BGE	0	0.0	619	891.4	7	79.8
ComEd	0	0.0	1,178	1,185.4	496	479.6
DAY	0	0.0	174	172.9	16	46.4
DLCO	0	0.0	722	1,055.8	3	5.6
Dominion	0	0.0	289	192.7	8	27.6
DPL	0	0.0	264	211.4	0	0.0
JCPL	0	0.0	324	210.4	0	0.0
Met-Ed	0	0.0	315	244.6	14	3.9
PECO	0	0.0	958	479.2	137	106.7
PENELEC	0	0.0	494	390.1	4	3.3
Pepco	0	0.0	452	309.0	5	3.3
PPL	0	0.0	944	735.2	28	10.5
PSEG	0	0.0	745	412.3	6	1.8
RECO	0	0.0	14	6.4	0	0.0
Total	0	0.0	10,132	10,334.3	819	1,188.4

38 Table 5-11 shows registered sites and MW in the Emergency Program as of July 22, 2011, the peak load day of 2011. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program and Table 5-12 reflects the same participation. Registered sites and MW remain constant in the LM Program through delivery years.

Load Management Program

The increase in registrations in the Emergency Program for peak periods in 2010 compared to 2009 is due to increased participation in the Load Management (LM) Program, that is, increased load response participation in RPM. Table 5-12 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2011/2012.

Table 5-12 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2011

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4
2011/2012	2,792.1	8,730.5	11,522.7

Table 5-13 shows zonal monthly capacity credits that were paid during the calendar year 2010 to ILR and DR resources. Capacity revenue decreased by $25 million or 4.9 percent, from $512 million in 2010 to $487 million in 2010. Credits from January to May are associated with participation in the 2010/2011 RPM delivery year, while credits from June to December are associated with participation in the 2011/2012 RPM delivery year. The decrease in capacity credits after May is the result of a decrease in RPM clearing prices.

Load Management Event Compliance

In calendar year 2011, PJM declared five Load Management events. The first and second events, declared on May 26, 2011 and May 31, 2011, affected resources committed in the 2010/2011 Delivery Year, as it occurred prior to June 1, 2011. However, since it fell outside of the summer compliance period of June through September, curtailment was not required and no compliance penalties were assessed for this event.[39] Participants that did curtail were eligible to receive emergency energy credits. The three following events were called on the same day, July 22, 2011, but as separate events. These events affected resources committed in the 2011/2012 Delivery Year. Since each of these events occurred within the summer compliance

39 See RAA, Schedule 6 § L.

Table 5-13 Zonal monthly capacity credits: Calendar year 2011

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$515,251	$465,388	$515,251	$498,630	$515,251	$332,740	$343,831	$343,831	$332,740	$343,831	$332,740	$343,831	$4,883,314
AEP	$7,718,744	$6,971,769	$7,718,744	$7,469,752	$7,718,744	$5,220,226	$5,394,234	$5,394,234	$5,220,226	$5,390,887	$5,216,988	$5,390,887	$74,825,436
APS	$4,272,819	$3,859,321	$4,272,819	$4,134,986	$4,272,819	$3,300,774	$3,410,799	$3,410,799	$3,300,774	$3,410,799	$3,300,774	$3,410,799	$44,358,284
ATSI	$0	$0	$0	$0	$0	$4,665	$4,821	$4,821	$4,665	$4,821	$4,665	$4,821	$33,277
BGE	$5,039,828	$4,552,103	$5,039,828	$4,877,253	$5,039,828	$3,513,455	$3,630,571	$3,630,571	$3,513,455	$3,630,571	$3,513,455	$3,630,571	$49,611,487
ComEd	$8,156,971	$7,367,587	$8,156,971	$7,893,843	$8,156,971	$5,965,794	$6,180,266	$6,180,266	$5,980,903	$6,180,266	$5,980,903	$6,180,266	$82,381,008
DAY	$1,151,545	$1,040,105	$1,151,545	$1,114,399	$1,151,545	$797,889	$824,485	$824,485	$797,889	$824,485	$797,889	$824,485	$11,300,748
DLCO	$1,118,544	$1,010,298	$1,118,544	$1,082,462	$1,118,544	$2,340	$2,418	$2,418	$2,340	$3,977,804	$3,849,488	$3,977,804	$17,263,005
Dominion	$5,447,494	$4,920,317	$5,447,494	$5,271,768	$5,447,494	$3,851,851	$3,980,247	$3,980,247	$3,851,851	$817,336	$790,970	$817,336	$44,624,406
DPL	$1,088,233	$982,920	$1,088,233	$1,053,128	$1,088,233	$790,970	$817,336	$817,336	$790,970	$2,418	$2,340	$2,418	$8,524,536
JCPL	$1,301,034	$1,175,128	$1,301,034	$1,259,066	$1,301,034	$854,729	$883,220	$883,220	$854,729	$883,220	$854,729	$883,220	$12,434,362
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$1,166,215	$1,205,089	$880,176	$909,516	$909,516	$880,176	$909,516	$880,176	$909,516	$12,148,541
PECO	$2,826,229	$2,552,723	$2,826,229	$2,735,060	$2,826,229	$2,300,272	$2,376,947	$2,376,947	$2,300,272	$2,375,286	$2,298,664	$2,375,286	$30,170,144
PENELEC	$1,827,610	$1,650,744	$1,827,610	$1,768,654	$1,827,610	$1,335,716	$1,380,240	$1,380,240	$1,335,716	$1,380,240	$1,335,716	$1,380,240	$18,430,336
Pepco	$1,307,359	$1,180,840	$1,307,359	$1,265,186	$1,307,359	$1,137,037	$1,174,938	$1,174,938	$1,137,037	$1,174,938	$1,137,037	$1,174,938	$14,478,965
PPL	$4,115,164	$3,716,922	$4,115,164	$3,982,417	$4,115,164	$2,651,235	$2,739,610	$2,739,610	$2,651,235	$2,739,610	$2,651,235	$2,739,610	$38,956,977
PSEG	$2,536,813	$2,291,315	$2,536,813	$2,454,980	$2,536,813	$1,431,581	$1,479,301	$1,479,301	$1,431,581	$1,468,327	$1,420,962	$1,468,327	$22,536,115
RECO	$9,266	$8,369	$9,266	$8,967	$9,266	$21,799	$22,526	$22,526	$21,799	$22,526	$21,799	$22,526	$200,634
Total	$49,637,993	$44,834,317	$49,637,993	$48,036,767	$49,637,993	$34,393,250	$35,555,305	$35,555,305	$34,408,359	$35,536,881	$34,390,530	$35,536,881	$487,161,575

Table 5-14 PJM declared Load Management Events: Calendar year 2011

Event Date	Event Times	Delivery Year	Geographical area
26-May-11	HE 1500 - 1900	2010/2011	Norfolk portion of Dominion
31-May-11	HE 1600 - 2000	2010/2011	AECO, BGE, Dominion, DPL, JCPL, Met-Ed PECO, Pepco, PENELEC, PSEG, RECO
22-Jul-11	HE 1300 - 1800	2011/2012	BGE (Short Lead Time)
22-Jul-11	HE 1300 - 1800	2011/2012	BGE (Long Lead Time)
22-Jul-11	HE 1400 - 2000	2011/2012	DLCO, DPL, JCPL, Met-Ed, PECO

period, each was considered in compliance assessment. Table 5-14 lists Load Management Events declared by PJM in calendar year 2011.

For all events listed in Table 5-14, except for a specific deployment of short lead time resource in BGE on July 22, 2011, PJM deployed only long lead time resources, which are those that require between one to two hours notification. As a result, the nominal ICAP stated in event compliance tables in this section may not equal total nominal ICAP for the zone. For the July 22 Event, PJM deployed short lead time resources for BGE in addition to long lead time resources. Short lead time resources are those which require no more than an hour notification. Approximately 95.5 percent of registrations, accounting for 83.2 percent of registered MW, are designated as long lead time resources.

The event on May 26 was the second time in the history of PJM Load Response Programs that PJM deployed emergency demand side resources subzonally. While all PJM Emergency Actions, including Load Management Events, may be issued for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each CSP to a zonal portfolio. Some market participants were not prepared to deploy resources on a subzonal level, and they submitted event compliance data for all resources within the Dominion Zone.

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. A requirement to identify the subzonal location of demand resources would be a positive step towards nodal pricing and the ability of PJM to deploy demand resources in a manner more consistent with the nodal deployment of generation and more consistent with nodal pricing. Without the ability to dispatch resources nodally, demand resources may be called where they are not needed. The Norfolk subzone of Dominion illustrated the need for subzonal dispatch, as weather events caused DR to be needed only within the Norfolk subzone, and outside this subzone any emergency response was unnecessary.

Table 5-15 Load Management event performance: July 22, 2011

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
BGE	1,001.7	956.8	962.1	5.3	100.6%	96.0%
BGE Short Lead	521.1	517.6	521.0	3.5	100.7%	100.0%
BGE Long Lead	480.6	439.3	441.1	1.8	100.4%	91.8%
DLCO	205.4	182.0	162.9	(19.1)	89.5%	79.3%
DPL	171.7	167.2	128.5	(38.7)	76.8%	74.8%
JCPL	183.0	177.4	141.1	(36.3)	79.5%	77.1%
Met-Ed	244.6	239.7	205.9	(33.8)	85.9%	84.2%
PECO	590.7	572.6	497.1	(75.4)	86.8%	84.2%
Total	2,397.0	2,295.7	2,097.6	(198.1)	91.4%	87.5%

Table 5-16 Distribution of participant event days across ranges of performance levels across the event in the 2011/2012 Delivery Year compliance period

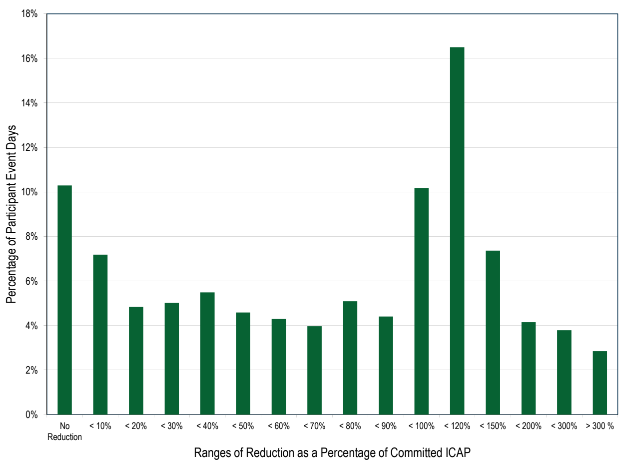
Ranges of performance as a percentage of committed MW	Number of participant event days	Proportion of participant event days	Cumulative Proportion
0% or no load reduction	285	10%	10%
0% -10%	199	7%	17%
10% - 20%	134	5%	22%
20% - 30%	139	5%	27%
30% - 40%	152	5%	33%
40% - 50%	127	5%	37%
50% - 60%	119	4%	42%
60% - 70%	110	4%	46%
70% - 80%	141	5%	51%
80% - 90%	122	4%	55%
90% - 100%	282	10%	65%
100% - 120%	457	16%	82%
120% - 150%	204	7%	89%
150% - 200%	115	4%	93%
200% - 300%	105	4%	97%
> 300%	79	3%	100%
Total	2,770	100%	

Table 5-15 shows performance for the July 22 event. The first column shows the nominal value which represents the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns may reflect differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not. Overall, the performance was 87.5 percent, or 2,097.6 MW out of 2,296.1 MW committed. BGE showed the highest MW reduction with 962.1 MW in observed load reduction or 46 percent of total observed load reduction, as well as the highest aggregated performance percentage of 100.6 percent.

Performance for specific customers varied significantly. Table 5-16 shows the distribution of participant event days across various levels of performance for the event in the 2011/2012 compliance period. For this event, approximately 17 percent of participants showed little or no reduction. Approximately 37 percent of participants did not meet half of their committed MW. The majority of participants, approximately 65 percent, showed less than 100 percent reduction to their commitment. Figure 5-3 shows the data in Table 5-16.[40] The distribution appears bimodal, with high frequencies of both low performing and over performing registrations. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting underperforming resources, and consistent with double counting.

40 Participant event days, shown in , Figure 5-3, and Table 5-17, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant even day. In addition, the load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 5-3 Distribution of participant event days across ranges of performance levels across the event in the 2011/2012 Delivery Year compliance period



It is difficult to determine whether Guaranteed Load Drop (GLD) customers have managed their PLCs without more load data than is provided for compliance settlements. However, one way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. Table 5-17 shows the distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of PLC for all events in the 2011/2012 Delivery Year.

About 77 percent of GLD participants submitting event compliance data show reductions in real time which are less than or equal to 75 percent of their PLC. These GLD participants account for 456 MW of event day reductions, which is 40 percent of GLD event day reductions and 22 percent of total event day reductions. Observed reductions for these customers account for 75 percent or less of their purchased capacity, which is based on historical peak usage levels.

About 14 percent of GLD participants submitting event compliance data show reductions in real time which are greater than or equal to 100 percent of their PLC. These GLD participants account for 584 MW of event day reductions, which is 51 percent of GLD reductions and 28 percent of total reductions. It is reasonable to conclude that such GLD customers, showing a reduction greater than or equal to PLC, did manage their PLCs in the prior year. Reductions from customers with reductions equal to from 150 percent to 300 percent or more of their PLC accounted for 29 percent of total GLD reductions. The results in Table 5-17 show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with double counting.

Emergency Energy Payments

For any PJM declared Load Management event in calendar year 2011, participants registered under the "Full" option of the Emergency Load Response Program that were deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which is equal to the higher of hourly zonal LMP or an energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. In other words, participants are paid their emergency offer, regardless of the zonal LMP. Table 5-18 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, about 73 percent, have a minimum dispatch price of $999/MWh or higher. Energy offers are further increased by shutdown costs submitted, which, in the 2011/2012 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective $/MWh energy offer.

Table 5-19 shows emergency credits and make whole payments for each event in calendar year 2011. The emergency credit is market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments represent the difference between the market valuation of the load reduction, based on zonal LMP, and the submitted energy offer.

Table 5-17 Distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2011/2012 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event days	Proportion of total GLD participant event days	Cumulative Proportion	Observed reductions (MW)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	1,017	50%	50%	157.7	14%	14%
25% - 50%	323	16%	66%	153.6	13%	27%
50% - 75%	234	11%	77%	144.7	13%	40%
75% - 100%	172	8%	86%	112.1	10%	49%
100% - 150%	183	9%	95%	249.4	22%	71%
150% - 200%	40	2%	97%	214.0	19%	90%
200% - 300%	36	2%	98%	24.7	2%	92%
300% or greater	35	2%	100%	95.8	8%	100%
Total	2,040	100%		1,152.0	100%	

Table 5-18 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2010/2011 Delivery Year

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total
$0 - $1	2,130	19.5%	3,407.2	29.6%
$1.01 - $200	90	0.8%	100.0	0.9%
$200 - $500	734	6.7%	503.8	4.4%
$500 - $998	39	0.4%	130.5	1.1%
$999+	7,958	72.7%	7,381.2	64.1%
Total	10,951	100.0%	11,522.7	100.0%

Table 5-19 Emergency credits and make whole payments by event: Calendar Year 2011

Event	Emergency Credits	Emergency Make Whole Payments	Total
31-May-11	$1,686,049	$2,332,381	$4,018,430
22-Jul-11	$4,259,202	$6,348,960	$10,608,162
Total	$5,945,250	$8,681,341	$14,626,592

Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and even capacity payments through the Load Management Program in that they are not based on or tied to any market price signal; they are simply guaranteed offers which are subject to no documentation or justification. In fact, their value should be aligned with the Economic Program, since it is designed to compensate for energy reductions and higher incentives would naturally occur as emergency events approach through higher energy market prices. However, because the two programs are not aligned and because the emergency credits are significantly more attractive to participants than Economic Program payments, there is an incentive for participants to delay any economic load reductions on days when an emergency event may be called.

In addition, the measurement protocol used to determine emergency energy payments is misaligned with other Load Response Programs. All emergency energy payments are based on the "same day" method, which is the difference between usage for one hour prior to the event and usage throughout the event. If a customer opts for a different method in performance calculations, the same event and same load reducing activities will be associated with two different load reduction values, one for emergency energy settlements, another for performance calculations.

Load Management Testing

In the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year which became effective in the 2009/2010 delivery year. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[41]

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

41 For more information, see PJM, "Manual 18, PJM Capacity Market", Revision 10 (June 1, 2010), Section 8.6.

Table 5-20 Load Management test results and compliance by zone for the 2011/2012 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	92.6	89.9	89.6	(0.3)	100%	97%
AEP	2,091.1	2,012.5	2,152.7	140.2	107%	103%
AP	931.8	920.2	944.0	23.8	103%	101%
ATSI	1,304.4	1,169.6	1,239.8	70.2	106%	95%
ComEd	1,665.0	1,633.0	1,730.3	97.3	106%	104%
DAY	222.7	222.2	246.5	24.3	111%	111%
DLCO	6.0	5.9	7.5	1.6	127%	125%
Dominion	1,152.5	1,106.7	1,089.8	(16.9)	98%	95%
DPL	48.7	48.6	48.7	0.1	100%	100%
JCPL	54.4	54.4	51.2	(3.2)	94%	94%
Met-Ed	3.9	3.9	5.3	1.4	136%	136%
PECO	1.4	1.4	1.2	(0.2)	86%	86%
PENELEC	401.3	400.8	434.3	33.5	108%	108%
Pepco	320.7	268.3	259.2	(9.1)	97%	81%
PPL	771.8	760.4	819.2	58.9	108%	106%
PSEG	419.9	404.0	437.7	33.7	108%	104%
RECO	6.4	6.4	4.6	(1.8)	72%	72%
Total	9,401.9	9,018.3	9,472.0	453.7	105%	101%

There were 9,018 MW of Committed ICAP not deployed in an event during the compliance period for the 2011/2012 Delivery year and thus required to perform testing. Load Management testing results are shown in Table 5-20. Overall, test results showed 453.7 MW available over RPM commitments, or 105 percent test compliance. The Met-Ed control zone showed the highest percentage of compliance, with load reductions at 136 percent of RPM Commitments, while the AEP control zone showed the highest level of MW reduction in testing, with load reductions at 2,152.7 MW, or 140.2 MW over RPM commitments.

Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.

Measurement and Verification

Traditionally, there have been two approaches to measurement and verification of demand side resources. The less common is specifying a firm MW level to which usage will be reduced. This method is limited to capacity based demand side products. In PJM's Load Management Program, this measurement and verification option is called Firm Service Level (FSL).

The more common approach for both economic and capacity demand side products is to establish a base line usage level by analyzing prior usage levels for a set of days that are intended to be representative of or similar to the day of the reduction. Similar can be defined by day of the week, peak or off peak, and, in more complicated scenarios, weather conditions. In the Economic Program, the baseline method is the default approach, and the standard baseline is referred to as Customer Baseline Load (CBL). In the Load Management Program, this measurement and verification option is called Guaranteed Load Drop (GLD) and there are several baseline methods to choose from. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

Baseline Pilot Study

On April 20, 2011 PJM issued a report from KEMA, which focused on potential improvements to the CBL methodology.[42] KEMA recommended the PJM economic CBL with a same day additive adjustment. KEMA concluded that same day additive adjustments perform better than an unadjusted or weather adjusted CBL. Some other CBLs were similar in accuracy, but required additional data or administrative burden in comparison to the PJM economic CBL. KEMA also recommended that rules be established to identify and mitigate any possible manipulation of CBLs.

Economic Program

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the standard CBL. The modifications to the CBL calculations currently occurring represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

Participants in the Economic Program are paid based on the reductions in MWh usage that can be attributed to demand side actions. Most participants in the Economic Program measure their reductions by comparing metered load against a Customer Baseline Load (CBL), or an estimate of what metered load would have been absent the reduction.[43] The default CBL employed for approximately 85 percent of Economic Program Participants is the simple average usage over the highest four of the last five similar days.

Customer Base Line (CBL) – History

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. PJM has made changes to improve the settlement review process, but more needs to be done.[44]

The current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

CBL Issues

The CBL is a generic formula applied to nearly every customer's usage and is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is

42 See "PJM Empirical Analysis of Demand Response Baseline Methods" <http://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx>.

43 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.

44 123 FERC ¶ 61,257 (2008).

below CBL. A customer's CBL calculation is only reviewed in the Economic Program registration process and the review criteria are unclear. In the registration process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC, though following Order 745 changes, CBLs must undergo a Relative Root Mean Squared Error (RRMSE) test to determine the most accurate method.[45] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment.

Determining the accuracy of a CBL is difficult. More data are required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, those are the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns.

In the future, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for a PJM Economic Load Response Program, or for an extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques are designed to estimate what consumption would have been, absent any load reducing activities.

Analysis of Settlements

PJM and the MMU only have access to meter data submitted as part of a settlement day. Neither PJM nor the MMU have sufficient data to determine if hours submitted for settlement represent deliberate actions taken or normal load fluctuations due to other variables.

The MMU has reported that a large number of consecutive hours showing a metered load less than CBL may be an indication that the CBL is not an adequate method to determine load reductions.[46] If a CBL is accurately modeling load patterns, then a CBL greater than real time load indicates load reducing actions are taking place. If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should trigger a CBL review and warrant further substantiation from the customer and CSP.

The occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load have decreased significantly every year since 2008. However, this does not indicate that the CBL is more accurate and there are still instances of requests for settlements passing the daily activity review screen that include 24 consecutive hours of reduction. These settlements are paid without any documentation of load reducing activities in response to real time price signals.

It is extremely implausible that any customer would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data.

The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

Load Management Program

There are three measurement and verification protocols in the Load Management (LM) Program: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD). The DLC method is used for 8 percent of registered MW in the LM Program, while the FSL method is used for 32 percent and the GLD method is used for 60 percent.[47]

45 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.

46 A similar and more extensive analysis of settlements also appears in the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1", p. 108.

47 Of the 56 percent of registered MW nominated as Guaranteed Load Drop, seven percent elect the behind the meter generation option for measurement and verification.

For DLC customers, a CSP will interface directly with customer equipment, sending a communication to reduce when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies. While customers are required to provide documentation of technical capabilities to enroll in this option, no telemetry or load data are required for verification of actual event performance. Rather, the CSP submits to PJM the time at which the equipment is deployed. There is no way for PJM or the MMU to determine if any load reduction took place in an emergency event.

GLD customers establish a baseline of unrestricted consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. The load reduction for GLD customers is the reduction of committed MW when an event is called. There are several techniques for estimation available to participants. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling.

FSL customers establish a firm consumption level which they must reach during an emergency event and the difference between that firm service level and the Peak Load Contribution (PLC) is the amount nominated in the LM Program. FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

The shortfalls of the standard CBL calculation used in the Economic Program have been identified, including the potential for an upward bias based on prior days with warmer temperatures. The potential for an upward bias during an actual Emergency Event is more limited, since Emergency Events coincide with peak load conditions in PJM which are highly correlated with peak temperatures. However, this design flaw is an issue when applied to Load Management testing as participants have discretion as to when testing will take place. Currently, GLD customers can test on any day in the summer period, and choose any other day in that period to serve as the baseline consumption for estimating load reductions. There are no objective criteria to establish comparability between the baseline day and test day.

The MMU recommends that any baseline approach designed to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants.

While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers. The baseline pilot study conducted by KEMA indicated that the CBL used by the PJM Economic Program is an improvement, and consequently should be used by the GLD option in the Load Management Program.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbines (CT), combined cycle (CC), and coal plant (CP) generating units.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs for both hypothetical new entrant units and for existing units is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources, including a competitive return on investment, when there is a market based need, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP.

- **Actual Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a measure of the extent to which units in PJM may be at risk of retirement.

  It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2011 was 5,642 MW. Generally, coal units that did not recover avoidable costs tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs.

Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units not recovering avoidable costs excluding capital recovery, as they may stay in service for the duration of the project life.

Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. The total installed capacity of sub-critical coal and supercritical coal units that do not have NO_x, SO_2, or particulate controls in place is 17,104 MW. Of the capacity lacking NO_x, SO_2, or particulate controls, 83 percent is associated with plants older than 40 years.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[1] The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NOx control, a Flue Gas Desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.

Net revenues for 2009, 2010 and 2011 were calculated using the most economic combination of day-ahead and real-time dispatch and more flexible scheduling than previously presented in order to more closely match the expected actual dispatch. As a result, net revenues may not match net revenue calculations from previous years.

All net revenue calculations include the hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[2,3] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NOx and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the PJM definition of marginal cost. NOx and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[4]

A forced outage rate for each class of plant was calculated from PJM data.[5] This class-specific outage rate was then incorporated into all revenue calculations. Each plant was also given a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of synchronized reserve service for all three plant types were set to zero. Ancillary service revenues for the provision of regulation service for both the CT and CC plant were also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability was assumed for the reference CT plant configuration in either costs or revenues.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2011, for CTs, the calculated rate is $2,384 per installed MW-year, for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[6] The delivered fuel cost for natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[7] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[8]

Average zonal operating costs in 2011 for a CT were $53.20 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $7.59 per MWh. Average zonal operating costs for a CP were $36.79 per MWh, based on a design heat rate of 9,240 Btu per kWh and a VOM rate of $3.22 per MWh. Average zonal operating costs for a CC were $32.75 per MWh, based on a design heat rate of 6,914 Btu per kWh and a VOM rate of $1.25

1 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
2 Hourly ambient conditions supplied by Telvent DTN.
3 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.
4 NOx and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
5 Outage figures obtained from the PJM eGADS database.
6 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
7 Gas daily cash prices obtained from Platts.
8 Coal prompt prices obtained from Platts.

per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.

The net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. Capacity revenue for 2011 includes five months of the 2010/2011 RPM auction clearing price and seven months of the 2011/2012 RPM auction clearing price.[9] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[10]

Table 6-1 Capacity revenue by PJM zones (Dollars per MW-year)[11]

Zone	2009	2010	2011	Average
AECO	$58,586	$61,406	$45,938	$55,310
AEP	$35,789	$48,898	$45,938	$43,542
AP	$53,440	$61,406	$45,938	$53,595
ATSI	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$63,342
ComEd	$35,789	$48,898	$45,938	$43,542
DAY	$35,789	$48,898	$45,938	$43,542
DLCO	$35,789	$48,898	$45,938	$43,542
Dominion	$58,586	$62,251	$46,530	$55,789
DPL	$35,789	$48,898	$45,938	$43,542
JCPL	$58,586	$61,406	$45,938	$55,310
Met-Ed	$53,440	$61,406	$45,938	$53,595
PECO	$58,586	$61,406	$45,938	$55,310
PENELEC	$53,440	$61,406	$45,938	$53,595
Pepco	$53,440	$61,406	$45,938	$53,595
PPL	$58,586	$61,406	$45,938	$55,310
PSEG	$76,236	$67,851	$45,938	$63,342
RECO	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$50,189

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start up costs. If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least four hours, or any hours bordering the profitable day ahead or real time block.

Table 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$8,990	$47,188	$0	$0	$2,384	$58,563
2010	$32,781	$55,186	$0	$0	$2,384	$90,351
2011	$34,939	$45,972	$0	$0	$2,384	$83,295

Table 6-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[12]

Zone	2009	2010	2011	Average
AECO	$11,373	$40,037	$46,157	$32,523
AEP	$3,275	$11,575	$20,839	$11,896
AP	$10,188	$32,494	$32,958	$25,213
ATSI	NA	NA	$15,129	$15,129
BGE	$13,644	$52,411	$48,642	$38,232
ComEd	$2,286	$9,446	$15,081	$8,938
DAY	$2,866	$11,701	$21,705	$12,091
DLCO	$3,366	$17,525	$24,179	$15,023
Dominion	$14,315	$42,922	$38,945	$32,061
DPL	$12,718	$40,530	$44,339	$32,529
JCPL	$10,527	$39,409	$44,968	$31,635
Met-Ed	$9,982	$39,409	$40,802	$30,064
PECO	$9,703	$38,311	$45,853	$31,289
PENELEC	$6,276	$24,309	$32,090	$20,892
Pepco	$16,205	$50,906	$44,233	$37,115
PPL	$9,104	$33,649	$42,872	$28,542
PSEG	$9,172	$37,626	$37,929	$28,242
RECO	$7,838	$35,022	$32,178	$25,013
PJM	$8,990	$32,781	$34,939	$25,570

9 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

10 The PJM capacity revenues differ slightly from those presented in Table 6-2, Table 6-5 and Table 6-8 as these capacity revenues by technology type are adjusted for technology-specific outage rates.

11 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the RECO zone.

12 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.

Table 6-4 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$70,894	$102,692	$94,495	$89,360
AEP	$40,562	$61,953	$69,177	$57,231
AP	$64,691	$95,149	$81,295	$80,378
ATSI	NA	NA	NA	NA
BGE	$90,378	$121,392	$96,979	$102,917
ComEd	$39,573	$59,824	$63,419	$54,272
DAY	$40,154	$62,079	$70,043	$57,425
DLCO	$40,654	$67,903	$72,516	$60,358
Dominion	$73,836	$106,406	$87,875	$89,373
DPL	$50,006	$90,908	$92,677	$77,864
JCPL	$70,048	$102,063	$93,306	$88,472
Met-Ed	$64,485	$102,063	$89,139	$85,229
PECO	$69,223	$100,966	$94,191	$88,127
PENELEC	$60,779	$86,964	$80,428	$76,057
Pepco	$70,708	$113,561	$92,571	$92,280
PPL	$68,625	$96,304	$91,209	$85,379
PSEG	$85,907	$106,607	$86,266	$92,927
RECO	NA	NA	NA	NA
PJM	$62,533	$92,302	$84,724	$79,853

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start up costs.[13] If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

Table 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$44,553	$50,184	$0	$0	$3,198	$97,936
2010	$89,027	$58,324	$0	$0	$3,198	$150,549
2011	$103,726	$48,306	$0	$0	$3,198	$155,230

13 All starts associated with combined cycle units are assumed to be hot starts.

Table 6-6 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$53,515	$106,643	$126,869	$95,676
AEP	$25,716	$47,591	$82,324	$51,877
AP	$51,473	$91,032	$113,561	$85,356
ATSI	NA	NA	$54,554	$54,554
BGE	$56,858	$124,665	$130,806	$104,110
ComEd	$18,383	$33,906	$46,293	$32,861
DAY	$23,596	$46,647	$82,067	$50,770
DLCO	$22,923	$51,180	$81,642	$51,915
Dominion	$58,612	$116,873	$114,530	$96,672
DPL	$55,142	$106,245	$123,599	$94,995
JCPL	$52,935	$105,474	$124,878	$94,429
Met-Ed	$47,338	$97,665	$111,653	$85,552
PECO	$49,620	$99,951	$121,804	$90,458
PENELEC	$42,010	$80,773	$109,048	$77,277
Pepco	$58,923	$121,952	$121,143	$100,673
PPL	$45,115	$87,314	$111,111	$81,180
PSEG	$50,355	$101,819	$114,951	$89,041
RECO	$44,897	$93,724	$96,235	$78,285
PJM	$44,553	$89,027	$103,726	$79,102

Table 6-7 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$117,477	$173,539	$178,353	$156,457
AEP	$66,034	$101,513	$133,808	$100,452
AP	$110,100	$157,928	$165,046	$144,358
ATSI	NA	NA	NA	NA
BGE	$139,127	$198,247	$182,290	$173,221
ComEd	$58,700	$87,828	$97,778	$81,435
DAY	$63,914	$100,569	$133,551	$99,345
DLCO	$63,241	$105,102	$133,126	$100,490
Dominion	$122,575	$184,646	$166,637	$157,952
DPL	$95,460	$160,167	$175,084	$143,570
JCPL	$116,897	$172,370	$176,362	$155,210
Met-Ed	$105,964	$164,561	$163,137	$144,554
PECO	$113,582	$166,847	$173,288	$151,239
PENELEC	$100,637	$147,669	$160,532	$136,279
Pepco	$117,549	$188,848	$172,628	$159,675
PPL	$109,077	$154,209	$162,595	$141,961
PSEG	$132,624	$175,401	$166,435	$158,153
RECO	NA	NA	NA	NA
PJM	$102,060	$152,465	$158,791	$137,772

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched by PJM operations in the Day Ahead market for all available plant hours, both reasonable assumptions for a large, efficient CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 6-8 PJM-wide net revenue for a CP under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$47,467	$47,469	$0	$2,051	$1,783	$98,770
2010	$119,478	$54,670	$0	$898	$1,783	$176,830
2011	$70,665	$44,282	$0	$1,025	$1,783	$117,754

Table 6-9 PJM Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$67,257	$149,022	$75,325	$97,201
AEP	$13,379	$56,227	$72,858	$47,488
AP	$36,322	$98,671	$99,020	$78,004
ATSI	NA	NA	$27,942	$27,942
BGE	$36,606	$80,689	$56,940	$58,078
ComEd	$30,169	$106,599	$94,493	$77,087
DAY	$19,206	$77,082	$65,842	$54,043
DLCO	$14,410	$76,395	$47,075	$45,960
Dominion	$36,506	$144,290	$77,310	$86,035
DPL	$30,404	$147,279	$94,908	$90,864
JCPL	$57,382	$147,559	$71,437	$92,126
Met-Ed	$45,652	$139,228	$61,703	$82,195
PECO	$60,767	$142,542	$74,834	$92,714
PENELEC	$59,243	$122,426	$95,440	$92,369
Pepco	$54,534	$160,627	$73,476	$96,212
PPL	$55,246	$114,549	$76,697	$82,164
PSEG	$135,308	$124,533	$47,550	$102,464
RECO	$54,556	$143,410	$59,111	$85,692
PJM	$47,467	$119,478	$70,665	$79,203

Table 6-10 Zonal combined net revenue from all markets for a CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$128,381	$211,318	$122,640	$154,113
AEP	$52,513	$106,646	$119,838	$92,999
AP	$92,558	$161,061	$145,923	$133,181
ATSI	NA	NA	NA	NA
BGE	$115,577	$149,741	$104,070	$123,129
ComEd	$69,425	$156,923	$141,347	$122,565
DAY	$58,242	$127,353	$112,811	$99,469
DLCO	$53,547	$126,764	$93,969	$91,427
Dominion	$97,920	$207,434	$125,181	$143,511
DPL	$69,771	$197,413	$142,154	$136,446
JCPL	$118,581	$209,844	$118,528	$148,984
Met-Ed	$101,945	$201,539	$108,685	$137,390
PECO	$121,923	$204,846	$121,782	$149,517
PENELEC	$115,208	$184,704	$142,161	$147,358
Pepco	$110,759	$222,926	$120,398	$151,361
PPL	$116,455	$176,936	$123,652	$139,015
PSEG	$213,276	$193,147	$95,458	$167,294
RECO	NA	NA	NA	NA
PJM	$102,255	$177,412	$121,162	$133,610

Net Revenue Adequacy

To put net revenue results in perspective, net revenues are compared to the annual, nominal levelized fixed costs for each technology. Nominal levelized fixed cost provides for the full recovery of and on capital and all the expenses of operating the facility over 20 years, at a constant nominal annual rate.

The extent to which net revenues cover the levelized fixed costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue.

In this section, net revenue includes net revenue from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary service.

Table 6-11 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	20-Year Levelized Fixed Cost		
	2009	2010	2011
Combustion Turbine	$128,705	$131,044	$110,589
Combined Cycle	$173,174	$175,250	$153,682
Coal Plant	$446,550	$465,455	$474,692

New Entrant Combustion Turbine

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CT.

Table 6-12 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year)

Zone	2009	2010	2011
AECO	55%	78%	85%
AEP	32%	47%	63%
AP	50%	73%	74%
ATSI	NA	NA	NA
BGE	70%	93%	88%
ComEd	31%	46%	57%
DAY	31%	47%	63%
DLCO	32%	52%	66%
Dominion	57%	81%	79%
DPL	39%	69%	84%
JCPL	54%	78%	84%
Met-Ed	50%	78%	81%
PECO	54%	77%	85%
PENELEC	47%	66%	73%
Pepco	55%	87%	84%
PPL	53%	73%	82%
PSEG	67%	81%	78%
RECO	NA	NA	NA
PJM	49%	70%	77%

Figure 6-1 compares zonal net revenue for a new entrant CT for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-2 shows zonal net revenue for the new entrant CT for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-1 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

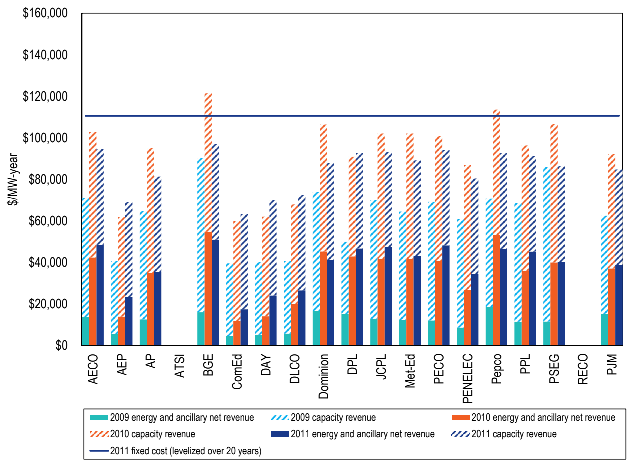


Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

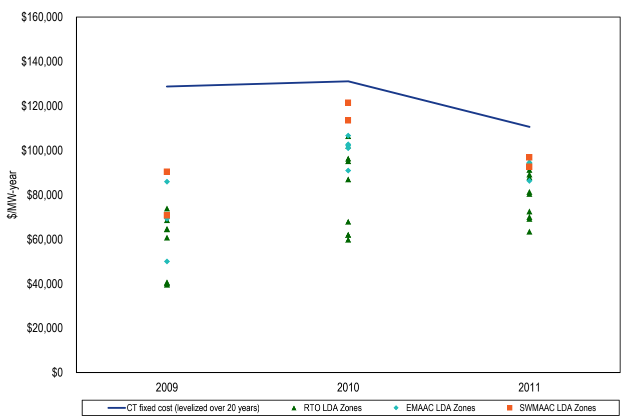
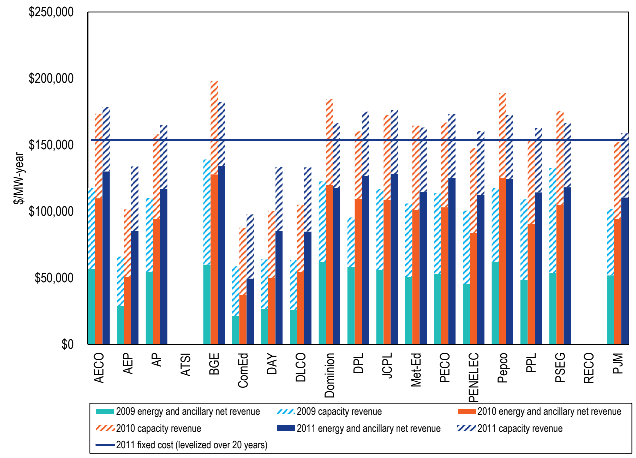


Figure 6-3 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)



New Entrant Combined Cycle

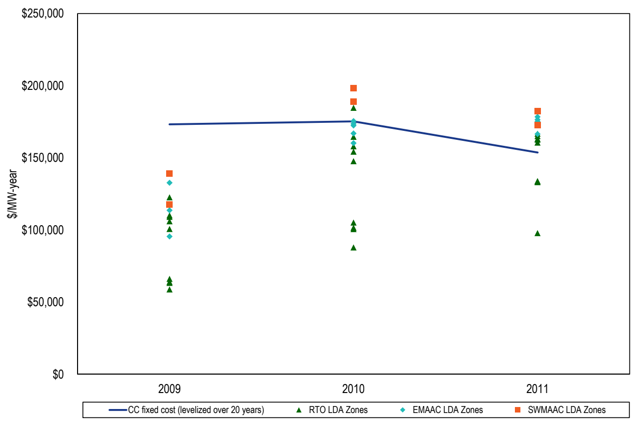
In 2011, all but four zones would have received net revenue sufficient to cover the levelized fixed costs of a new CC.

Figure 6-3 compares zonal net revenue for a new entrant CC for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-4 shows zonal net revenue for the new entrant CC for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Table 6-13 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011
AECO	68%	99%	116%
AEP	38%	58%	87%
AP	64%	90%	107%
ATSI	NA	NA	NA
BGE	80%	113%	119%
ComEd	34%	50%	64%
DAY	37%	57%	87%
DLCO	37%	60%	87%
Dominion	71%	105%	108%
DPL	55%	91%	114%
JCPL	68%	98%	115%
Met-Ed	61%	94%	106%
PECO	66%	95%	113%
PENELEC	58%	84%	104%
Pepco	68%	108%	112%
PPL	63%	88%	106%
PSEG	77%	100%	108%
RECO	NA	NA	NA
PJM	59%	87%	103%

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



New Entrant Coal Plant

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CP. No zone received sufficient net revenue to cover even 40 percent of the levelized fixed costs.

Table 6-14 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011
AECO	29%	45%	26%
AEP	12%	23%	25%
AP	21%	35%	31%
ATSI	NA	NA	NA
BGE	26%	32%	22%
ComEd	16%	34%	30%
DAY	13%	27%	24%
DLCO	12%	27%	20%
Dominion	22%	45%	26%
DPL	16%	42%	30%
JCPL	27%	45%	25%
Met-Ed	23%	43%	23%
PECO	27%	44%	26%
PENELEC	26%	40%	30%
Pepco	25%	48%	25%
PPL	26%	38%	26%
PSEG	48%	41%	20%
RECO	NA	NA	NA
PJM	23%	38%	26%

Figure 6-5 compares zonal net revenue for a new entrant CP for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-6 shows zonal net revenue for the new entrant CP for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-5 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

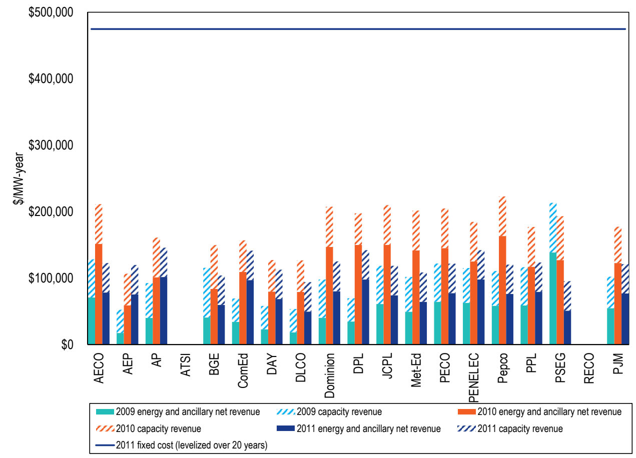
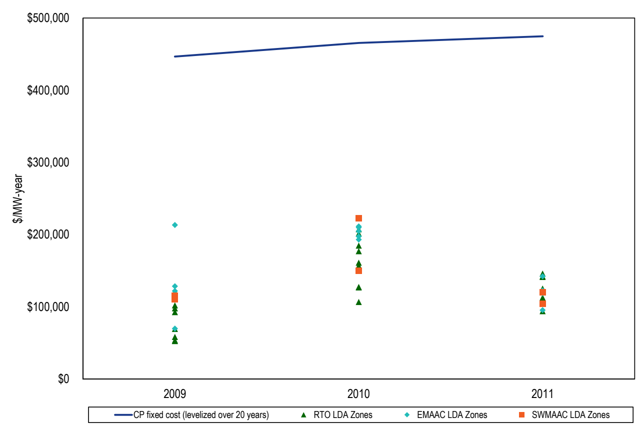


Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of net revenue indicates that the contribution of capacity revenue from RPM comprises a larger share of net revenue for a new entrant CT than for the CC or CP technologies. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more

Table 6-15 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$118,089	13.8%	$163,682	13.7%	$504,692	13.7%
Base Case	$110,589	12.0%	$153,682	12.0%	$474,692	12.0%
Sensitivity 2	$103,089	10.1%	$143,682	10.2%	$444,692	10.3%
Sensitivity 3	$95,589	8.1%	$133,682	8.4%	$414,692	8.5%
Sensitivity 4	$88,089	6.0%	$123,682	6.4%	$384,692	6.6%
Sensitivity 5	$80,589	3.5%	$113,682	4.3%	$354,692	4.6%
Sensitivity 6	$73,089	0.5%	$103,682	1.9%	$324,692	2.4%

dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2011, the yearly average operating cost of the CC was lower than the average operating costs of the CP, driven by the decreasing cost of gas and increasing cost of coal.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market. However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2011, zonal energy net revenues increased significantly for most CCs and CTs, while capacity market prices decreased in all zones. As a result, there were some zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CC in 2011.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 6-11. The results are shown in Table 6-15.[14]

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 6-16 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR

14 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

falls. Table 6-17 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 6-16 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$117,666	$163,034
Sensitivity 2	55%	$114,127	$158,358
Base Case	50%	$110,589	$153,682
Sensitivity 3	45%	$107,050	$149,006
Sensitivity 4	40%	$103,512	$144,330
Sensitivity 5	35%	$99,974	$139,654
Sensitivity 6	30%	$96,435	$134,978

Table 6-17 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$99,512	$139,050
Sensitivity 2	25	$103,698	$144,582
Base Case	20	$110,589	$153,682
Sensitivity 3	15	$116,378	$161,332
Sensitivity 4	10	$124,054	$171,475

Table 6-18 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs, the actual avoidable costs include APIR when unit owners have included APIR in unit offers. This affects the interpretation of the conclusions. Existing APIR is a sunk cost and a rational decision about retirement would ignore such

Table 6-18 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0%	$107,213	$0	0%	$150,034
Sensitivity 2	$4,811	2%	$108,900	$7,692	1%	$151,858
Base Case	$9,622	3%	$110,589	$15,383	2%	$153,682
Sensitivity 3	$14,433	5%	$112,277	$23,075	4%	$155,507
Sensitivity 4	$19,244	6%	$113,965	$30,766	5%	$157,331
Sensitivity 5	$24,055	8%	$115,653	$38,458	6%	$159,155
Sensitivity 6	$28,866	9%	$117,341	$46,149	7%	$160,980
Sensitivity 7	$50,000	16%	$124,756	$50,000	8%	$161,893
Sensitivity 8	$75,000	24%	$133,531	$75,000	11%	$167,822
Sensitivity 9	$100,000	32%	$142,302	$100,000	15%	$173,751

Table 6-19 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,236	$15,109	$59,208	$33,169
CC - Two of Three on One Frame F Technology	15,235	$73,628	$120,348	$18,215
CT - First & Second Generation Aero (P&W FT 4)	3,702	$7,436	$52,014	$15,486
CT - First & Second Generation Frame B	3,764	$4,574	$49,920	$12,398
CT - Second Generation Frame E	10,619	$22,231	$67,715	$7,217
CT - Third Generation Aero	3,696	$26,132	$73,816	$16,073
CT - Third Generation Frame F	9,026	$24,920	$69,935	$9,178
Diesel	495	$43,441	$86,074	$7,552
Hydro	1,975	$209,469	$254,535	$25,618
Nuclear	29,741	$240,376	$284,895	NA
Oil or Gas Steam	9,015	$22,308	$62,952	$46,228
Pumped Storage	4,952	$11,586	$61,158	$15,036
Sub-Critical Coal	31,096	$60,180	$98,485	$69,503
Super Critical Coal	24,653	$77,487	$111,428	$96,249

sunk costs. Potential APIR is not a sunk cost and a rational decision about retirement would consider the expected probability of recovering the costs of such new investments over the remaining life of the unit.

The MMU calculated unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on actual submitted Avoidable Cost Rate (ACR) data for units associated with the most recent 2010/2011 and 2011/2012 RPM Auctions.[15] For units that did not submit ACR data, the default ACR was used.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2010/2011 and 2011/2012 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[16] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied, which may understate actual revenues, since units may bid an export price into the auction as an opportunity cost and provide capacity to the market with the higher price.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 6-19 provides a summary of

15 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

16 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

Table 6-20 Energy and ancillary service net revenue by quartile for select technologies for calendar year 2011

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$7,443	$26,432	$90,547
CC - Two of Three on One Frame F Technology	$35,131	$79,038	$102,517
CT - First & Second Generation Aero (P&W FT 4)	$1,960	$4,765	$11,467
CT - First & Second Generation Frame B	$1,128	$3,940	$7,799
CT - Second Generation Frame E	$6,096	$12,826	$33,589
CT - Third Generation Aero	$14,222	$25,227	$34,658
CT - Third Generation Frame F	$10,139	$16,559	$34,776
Diesel	$1,475	$1,990	$5,967
Hydro	$103,780	$202,072	$250,008
Nuclear	$183,106	$266,044	$294,493
Oil or Gas Steam	$1,452	$4,644	$13,004
Pumped Storage	$0	$2,606	$5,064
Sub-Critical Coal	$24,072	$56,123	$86,062
Super Critical Coal	$55,366	$78,780	$97,698

Table 6-21 Capacity revenue by quartile for select technologies for calendar year 2011

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$41,866	$46,794	$47,855
CC - Two of Three on One Frame F Technology	$47,291	$48,149	$49,010
CT - First & Second Generation Aero (P&W FT 4)	$41,809	$44,306	$48,973
CT - First & Second Generation Frame B	$39,182	$47,120	$49,436
CT - Second Generation Frame E	$45,732	$48,737	$49,858
CT - Third Generation Aero	$46,208	$48,862	$49,575
CT - Third Generation Frame F	$44,177	$47,573	$48,533
Diesel	$43,492	$47,175	$51,437
Hydro	$44,259	$48,567	$49,858
Nuclear	$48,015	$49,023	$49,418
Oil or Gas Steam	$40,175	$46,396	$48,534
Pumped Storage	$48,932	$49,181	$49,459
Sub-Critical Coal	$41,468	$46,071	$48,239
Super Critical Coal	$24,231	$44,686	$47,074

Table 6-22 Combined revenue from all markets by quartile for select technologies for calendar year 2011

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$49,310	$73,226	$138,402
CC - Two of Three on One Frame F Technology	$82,422	$127,186	$151,527
CT - First & Second Generation Aero (P&W FT 4)	$43,769	$49,071	$60,440
CT - First & Second Generation Frame B	$40,310	$51,060	$57,235
CT - Second Generation Frame E	$51,828	$61,563	$83,447
CT - Third Generation Aero	$60,430	$74,089	$84,233
CT - Third Generation Frame F	$54,316	$64,132	$83,309
Diesel	$44,966	$49,165	$57,404
Hydro	$148,039	$250,639	$299,865
Nuclear	$231,121	$315,067	$343,911
Oil or Gas Steam	$41,627	$51,040	$61,538
Pumped Storage	$48,932	$51,787	$54,523
Sub-Critical Coal	$65,539	$102,195	$134,302
Super Critical Coal	$79,597	$123,466	$144,772

results by technology class, as well as the total installed capacity associated with each technology analyzed.

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 6-19 incorporate a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are useful in presenting the range of data

Table 6-23 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for calendar year 2011

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	54%	157%	435%
CC - Two of Three on One Frame F Technology	226%	363%	807%
CT - First & Second Generation Aero (P&W FT 4)	23%	65%	104%
CT - First & Second Generation Frame B	12%	37%	83%
CT - Second Generation Frame E	92%	144%	363%
CT - Third Generation Aero	130%	161%	228%
CT - Third Generation Frame F	106%	187%	291%
Diesel	6%	38%	1,731%
Hydro	663%	882%	950%
Nuclear	NA	NA	NA
Oil or Gas Steam	3%	10%	38%
Pumped Storage	NA	NA	NA
Sub-Critical Coal	31%	89%	140%
Super Critical Coal	89%	139%	212%

Table 6-24 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2011

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	220%	296%	635%
CC - Two of Three on One Frame F Technology	460%	726%	1,100%
CT - First & Second Generation Aero (P&W FT 4)	282%	522%	676%
CT - First & Second Generation Frame B	362%	530%	672%
CT - Second Generation Frame E	659%	709%	921%
CT - Third Generation Aero	387%	573%	632%
CT - Third Generation Frame F	609%	789%	959%
Diesel	420%	707%	2,735%
Hydro	849%	1,061%	1,163%
Nuclear	NA	NA	NA
Oil or Gas Steam	87%	177%	209%
Pumped Storage	186%	443%	664%
Sub-Critical Coal	90%	148%	203%
Super Critical Coal	127%	201%	284%

while avoiding the influence of outliers. The the three break points between the quartiles are presented. Table 6-20 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class.

Table 6-23 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2011, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 6-24 shows the avoidable cost recovery from all PJM markets by quartiles. In 2011, the majority of units in all technology classes received energy, ancillary and capacity revenue well in excess of avoidable costs.

Table 6-25 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets for 2009, 2010 and 2011. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM.

Table 6-25 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 to 2011

	2009		2010		2011	
Technology	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	57%	96%	83%	92%	64%	89%
CC - Two of Three on One Frame F Technology	63%	89%	84%	100%	87%	97%
CT - First & Second Generation Aero (P&W FT 4)	24%	99%	34%	100%	32%	99%
CT - First & Second Generation Frame B	30%	100%	34%	98%	29%	94%
CT - Second Generation Frame E	60%	100%	67%	100%	82%	100%
CT - Third Generation Aero	23%	99%	49%	99%	87%	99%
CT - Third Generation Frame F	41%	98%	69%	100%	79%	98%
Diesel	69%	97%	71%	97%	61%	91%
Hydro	100%	100%	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%	100%	100%
Oil or Gas Steam	36%	90%	40%	87%	43%	86%
Pumped Storage	45%	100%	90%	100%	70%	100%
Sub-Critical Coal	66%	88%	73%	88%	63%	77%
Super Critical Coal	74%	91%	77%	80%	81%	88%

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for most units that do not recover 100 percent of fixed costs through energy market revenue.

A significant number of sub-critical and supercritical coal units did not recover avoidable costs from energy market revenues alone in 2011. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal units relies more heavily on energy market revenues.

At-Risk Coal Plants

A number of sub-critical and supercritical coal units did not recover avoidable costs even including capacity market revenues. These units are considered at risk of retirement.

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[17]

Energy market net revenues are a function of energy prices and operating costs. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 6-26 compares characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues, to characteristics of coal plants with greater than or equal to 100 percent recovery. Units that did not cover their avoidable costs were, on average, less efficient and ran less often.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. Units that did not cover avoidable costs tended to have higher avoidable costs. It is possible that these units cleared in the capacity market at a level below avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated with each delivery year which led to an offer cap that understated the annual recovery needed from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap, including APIR. Such offers are rational, for example, if project costs are considered sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate. In either case, these units may be at a lower risk of retirement than units under recovering

17 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

avoidable costs exclusive of the recovery of capital investments.

Table 6-26 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	5,642	36,383
Avg. Installed Capacity (ICAP)	235	319
Avg. Age of Plant (Years)	46	38
Avg. Heat Rate (Btu/kWh)	11,135	10,701
Avg. Run Hours (Hours)	4,300	5,627
Avg. Avoidable Costs ($/MW-year)	512	146

In 2011, 73 coal units had capacity less than or equal to 200 MW. Of these units, 19 percent did not cover their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 6-27 shows the installed capacity (MW) associated with levels of recovery for coal plants.

Table 6-27 Installed capacity associated with levels of avoidable cost recovery: Calendar year 2011

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	3,793	9%
65% - 75%	111	0%
75% - 90%	465	1%
90% - 100%	1,273	3%
> 100%	36,383	87%
Total	42,025	100%

Impact of Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. There are pending regulations that would require significant capital expenditures on environmental controls for existing units. These capital expenditures, if required, would significantly impact the profitability of coal plants lacking sufficient environmental controls. Coal plants facing capital expenditures may be retired if it is not expected that the plants will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.

The MMU analyzed the impact that pending environmental regulations regarding SO_2 and NO_X emissions and particulate control may have on coal plants in the PJM footprint.[18] A number of coal plants that would have had to invest in MATS compliant environmental technology have either already started the deactivation process or are expected to request deactivation.[19] Units lacking MATS compliant controls for NO_X emissions, SO_2 emissions, particulates, or all three, were identified as units potentially facing significant capital expenditures on environmental control technologies. Table 6-28 shows the number of units and associated installed capacity lacking MATS compliant environmental controls.

Table 6-28 Coal plants lacking MATS compliant environmental controls

	Coal plants without NO_X controls	Coal plants without SO_2 controls	Coal plants without particulate controls	Coal plants lacking NO_X, SO_2, and particulate controls
Number of units	62	41	52	23
Installed capacity (ICAP)	11,806	7,441	13,806	2,980

Table 6-29 compares attributes of coal plants with controls in place to units that lack controls for NO_X emissions, SO_2 emissions, particulates, or all three.

The MMU estimated the cost of installing MATS compatible environmental controls for each unit to determine at risk units.[20] Table 6-30 shows at risk units, which include units that did not cover their avoidable costs from all market revenues in addition to units that would not be able to cover the cost of installing MATS compliant environmental controls from all market revenues. A comparison of Table 6-30 to Table 6-26 shows that only 122 MW of additional coal capacity, for which plans to retire have not already been indicated, are at risk due to MATS compliance. The additional MW of coal capacity at risk to due to MATS compliance risk increases 1,294 MW if the threshold is increased to 125 percent recovery of avoidable costs.

18 FRR committed units are excluded from this analysis since they receive compensation out of PJM Markets.

19 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

20 Costs of environmental controls provided by Pasteris Energy, Inc.

Table 6-29 Attributes of coal plants with and without MATS compliant environmental controls

	Coal plants lacking NO_x, SO_2, or particulate controls	Coal plants with NO_x, SO_2, and particulate controls
Number of units (excluding announced or expected deactivations)	80	58
ICAP within MAAC	6,618	5,247
ICAP in rest of RTO	10,487	19,674
Total installed capacity (ICAP)	17,104	24,921
ICAP associated with plants older than 40 years	14,248	9,216
ICAP associated with small coal plants (200 MW or less)	5,958	2,001
ICAP associated with medium coal plants (200 to 500 MW)	2,495	4,915
ICAP associated with large coal plants (500 MW or greater)	8,652	18,005
ICAP associated with 100 percent recovery of avoidable costs	14,927	21,456
ICAP associated with less than 100 percent recovery of avoidable costs	2,177	3,465

Table 6-30 At risk coal plants

	Coal plants covering less than	
	100% of avoidable costs or 100% of APIR (if any)	125% of avoidable costs or 125% of APIR (if any)
Number of units	26	30
ICAP within MAAC	1,630	1,765
ICAP in rest of RTO	4,135	5,172
Total installed capacity (ICAP)	5,764	6,936

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) and the Cross-State Air Pollution Rule (CSAPR) will require significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal and SO_2 and NO_x emissions. These investments may result in higher offers in the capacity market, and if units do not clear, in the retirement of some units. Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar-powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have, as a result, had a significant impact on PJM wholesale markets.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule (MATS).**[1] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources). In addition, in a related EPA rule issued on the same date regarding New Source Performance Standards (NSPS), a rule also referred to as part of MATS, the EPA requires new electric generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_x and filterable particulate matter.

- **Cross-State Air Pollution Rule (CSAPR).** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia. This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to a Federal Court of Appeals order directing revisions compliant with the requirements of the CAA. CSAPR was expected to become effective January 1, 2012, but a stay issued on December 30, 2011, by the Federal Court of Appeals considering petitions to review CSAPR, prevents such implementation pending a decision on the merits. CAIR will remain in effect pending such resolution.

- **National Emission Standards for Reciprocating Internal Combustion Engines (RICE).** The EPA recently issued rules regulating owners and operators of wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter and often used to provide demand side resources in the RPM. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs), and particulate matter.

  Several curtailment service providers (CSPs) reached a settlement with the EPA regarding their appeals in Federal Court, resulting in a commitment by the EPA to file revised rules that would accommodate participation by RICE in emergency demand response programs administered by Independent System Operators. The Market Monitoring Unit objected to the settlement, explaining that it did

1 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

not enhance clean air, participation by demand side resources in the organized markets nor reliability.[2] If approved, the settlement would require the EPA Administrator to take final action on the rules substantially consistent with the settlement by December 14, 2012.

- **Greenhouse Gas Tailoring Rule.** On May 13, 2010, the EPA issued a rule regulating CO_2 and other greenhouse gas emissions under the existing framework of new source review (NSR) and prevention of significant deterioration (PSD). As a result, new or modified units must install or implement the best available control technology (BACT). State environmental regulators determine BACT project by project, with guidance from the EPA.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey has addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as "High Electric Demand Days" or "HEDD," and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on HEDD. New Jersey's HEDD rule,[3] which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBTU and lack identified emission control technologies.[4] New Jersey's HEDD rule will be implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates.

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. After December 31, 2011, the State of New Jersey will no longer participate in the RGGI program. Auction prices in 2011 for the 2009-2011 compliance period were $1.89 throughout the year, which was the price floor for 2011.

Renewables and Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. At the end of 2011, 64.5 percent of coal steam MW's had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.0 percent of coal steam MW's had some type of particulate control. NOx emission controlling technology is used by nearly all fossil fuel unit types, and 90.4 percent of fossil fuel fired capacity in PJM has NOx emission control technology in place.

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2011, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 8.30 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out-of-market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

2 See In the Matter of: EnerNOC, Inc., et al., Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).
3 N.J.A.C. § 7:27-19.
4 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

Conclusion

Initiatives at both the Federal and state levels have an impact on the cost of energy and capacity in PJM markets. PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that could be used to incorporate renewable resource requirements to ensure that renewable resources have access to a broad market and are priced competitively so as to reflect their market value. PJM markets can provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. EPA issues technology based standards for major sources and certain area sources of emissions.[5,6] In recent years, the EPA has been actively defining and tightening its standards and considering potential mechanisms, such as cap and trade, to facilitate meeting those standards. EPA actions have and are expected to continue to affect the costs to build and operate generating units in PJM which in turn affect wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the CAA affects generating plants that draw water from jurisdictional water bodies.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.

The CAA requires the standards to reflect the maximum degree of reduction in hazardous air pollutant emissions that is achievable taking into consideration the cost of achieving the emissions reductions, any non air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the Maximum Achievable Control Technology (MACT). The MACT floor is the minimum control level allowed for NESHAP and ensures that all major hazardous air pollutant emission sources achieve the level of control already achieved by the better-controlled and lower-emitting sources in each category. Section 112 of the CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing 5 sources for source categories with less than 30 sources).

On December 16, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which is actually two separate rules issued on the same date.[7] One rule applies the MACT requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide (MATS/MACT Rule). The rule establishes a compliance deadline of April 16, 2015, near the end of the 2014/2015 RPM Delivery Year. A source may obtain an extension for up to one additional year where necessary for the installation of controls.

The MATS/MACT Rule sets emissions limits separately for each pollutant. The rule differs from the initial MACT proposal in several significant respects. Only filterable particulate matter (PM), as opposed to both filterable and condensable PM, is considered for compliance with emissions limits. Work practice standards are included for startup and shutdown periods. The rule extends the period of averaging for Hg from 30 to 90 days, but tightens the applicable standards for sources using averaging. The rule narrows the options for demonstrating continuous compliance to either continuous monitoring or periodic quarterly testing. The revised rule establishes seven categories of units covered by various requirements.

5 42 U.S.C. § 7401 et seq. (2000).

6 EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

7 Mercury Air Toxics Standards (MATS) rule, National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA Docket Nos. EPA-HQ-OAR-2009-0234 & EPA-HQ-OAR-2011-0044.

The other MATS rule sets New Source Performance Standards (NSPS)(MATS/NSPS Rule). The MATS/NSPS Rule requires new electric generating units constructed after May 3, 2012, to comply with amended emission standards for SO_2, NO_x and filterable Particulate Matter.

Control of NO_x and SO_2 Emissions

The CAA requires States to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[8] The EPA has sought to promulgate default Federal rules to achieve this objective.

The CAA requires EPA to review and, if appropriate, revise the air quality criteria for the primary (health-based) and secondary (welfare-based) NAAQS every five years. The NAAQS are the targets to which compliance mechanisms such as the rules regulating transport are directed. A final rule on SO_2 primary NAAQS was published June 22, 2010.[9] The EPA has initiated proceedings to review secondary NAAQS for NO_x and SO_x and primary and secondary NAAQS for Ozone (O_3). Proposed rules are expected to issue, respectively, in July, 2011 and May, 2013.[10] Additionally, on September 22, 2011, the EPA issued draft guidance regarding determining compliance with one-hour SO_2 NAAQS State Implementation Plan submissions.[11] If adopted, the approach outlined in the draft guidance could impact the attainment status of generating units within PJM, and require additional controls for SO_2.

On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), the latest in a series of rules aimed at regulating transport. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_x that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[12] The CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[13] This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to an order of the U.S. Court of Appeals for the District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act.

The CSAPR and its initial emissions caps were expected to become effective January 1, 2012, and to be reduced substantially two years later, on January 1, 2014. An order of the U.S. Court of Appeals for the District of Columbia has disrupted this timetable. On December 30, 2011, the Court issued a stay of the implementation of the CSAPR pending resolution of pending petitions for review.[14] The timetable for completing that review is uncertain. The Court stated that in the meantime EPA "is expected to continue administering [CAIR]." EPA has reinstated CAIR and restored 2012 CAIR allowances to accounts on January 10, 2012.[15]

It is unclear how effectively CAIR can be reestablished. The CSAPR does not recognize CAIR trading credits. EPA froze and then reinstituted CAIR trading accounts. These and other factors may influence the nature of continued participation in CAIR. The case will not be heard on the merits until a hearing convenes in April, 2012. A reasonable evaluation of whether or in what form CSAPR will survive cannot be made prior to that hearing.[16]

The discussion here assumes that CSAPR eventually becomes effective in its current form, and those assumptions were relevant to market expectations and behavior in 2011. Whether or in what form the CSAPR does take effect depends upon developments in 2012 and beyond.

CSAPR establishes two groups of states with separate requirements standards. "Group 1" includes a core region comprised of 21 states, including all of the PJM states

8 CAA § 110(a)(2)(D)(i)(I).

9 See 40 CFR Parts 50, 53, and 58.

10 See EPA Docket No. EPA-HQ-OAR-2007-1145 and EPA-HQ-OAR-2008-0699.

11 EPA, Draft Guidance for 1-Hour SO_2 NAAQS SIP Submissions (Draft September 22, 2011).

12 Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (CSAPR); Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012) (CSAPR II).

13 Id.

14 USCA Case No. 11-1302, Document #1350421.

15 See EPA website at <http://www.epa.gov/airmarkets/progsregs/cair/index.html>.

16 EPA states on its website: "The court's decision is not a decision on the merits of the rule and EPA firmly believes that when the court does weigh the merits of the rule it will ultimately be upheld" (<http://epa.gov/airtransport/faqs.html>). However, the likelihood that the party seeking the stay will prevail on the merits of the appeal is one of the factors considered in the decision to grant a stay. Cuomo v. United States Nuclear Regulatory Comm'n, 772 F.2d 972, 974 (D.C. Cir. 1985) (citing Washington Metro. Area Transit Comm'n v. Holiday Tours, Inc., 559 F.2d 841, 843 (D.C. Cir. 1977)); accord Hilton v. Braunskill, 481 U.S. 770, 776 (1987).

except Delaware, and also excluding the District of Columbia.[17] "Group 2" does not include any states in the PJM region.[18] Group 1 states must reduce both annual SO_2 and NO_x emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[19] NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Table 7-1 2012 and 2014 assurance levels (Tons) for SO_2[20] NO_x and O_3 season NO_x[21] emissions

	SO_2		NO_x		O_3 Season NO_x	
	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level	2012 Assurance Level	2014 Assurance Level
Illinois	277,169	146,465	56,489	56,489	25,662	25,662
Indiana	336,800	190,111	129,477	127,940	56,720	55,872
Kentucky	274,541	125,415	100,401	91,141	43,762	39,536
Maryland	35,542	33,280	19,627	19,557	8,687	8,687
Michigan	270,578	169,914	77,197	74,387	31,160	29,920
New Jersey	9,051	6,577	9,069	8,706	4,809	4,328
North Carolina	161,520	67,992	59,693	49,033	26,823	22,331
Ohio	366,071	161,751	109,390	103,242	48,476	45,728
Pennsylvania	328,808	132,185	141,583	140,649	63,163	62,814
Tennessee	174,817	69,423	42,130	22,818	18,039	9,699
Virginia	83,568	41,367	39,226	39,226	17,487	17,487
West Virginia	172,485	89,288	70,177	64,407	30,592	28,182

Emission reductions were expected to become effective starting January 1, 2012, for SO_2 and annual NO_x reductions and May 1, 2012, for ozone season NO_x reductions. CSAPR requires reductions of emissions for each state below certain "assurance levels," established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a "variability limit," which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

Significant additional SO_2 emission reductions would be required in 2014 from certain states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

The rule would implement a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, units in PJM states may only trade and use allowances originating in Group 1 states.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty would be assessed that is allocated to resources within the state in proportion to their responsibility for the excess. The penalty would be a requirement to surrender two additional allowances for each allowance needed to the cover the excess. The EPA will not assess assurance level penalty provisions until January 1, 2014.[22]

Table 7-1 shows the assurance levels applicable in 2012 and 2014 for SO_2, NO_x and seasonal ozone for each PJM state.

Emission Standards for Reciprocating Internal Combustion Engines

The EPA recently issued rules regulating owners and operators of a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter and are often used to provide demand side resources in the RPM market. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal

17 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

18 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

19 EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM (PM2.5) measures less than 2.5 microns across.

20 Annual NO_x assurance levels for Michigan and Annual NO_x and SO_2 and Seasonal NO_x for New Jersey are as set forth in the Technical Revisions to State Budgets and New Unit Set-Asides, Docket No. EPA-HQ-2009-0491 (October 2011) at 5 (Table 1.208.b) & 38 (Table 10.h), which includes changes approved in Federal Implementation Plans for Iowa, Michigan, Missouri, Oklahoma, and Wisconsin and Determination for Kansas Regarding Interstate Transport of Ozone, Final Rule, DPA Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 80760 (December 27, 2011).

21 CSAPR at 48269–70 (Tables VI.F-1, F-2 & F-3); Proposed Revised CSAPR at 40666 (Table 1.C-2).

22 See CSAPR II at 10330.

Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[23]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NOX, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn upon the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition). Spark ignition facilities are further subdivided.

A number of curtailment service providers petitioned the United States Court of Appeals for the District of Columbia Circuit for review of certain aspects of the RICE Rules.[24] On December 28, 2011, the EPA released a Notice of Proposed Settlement Agreement and Request for Public Comment that would allow owners and operators of emergency stationary internal combustion engines to operate emergency stationary internal combustion engines in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 60 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. Under the settlement, the rules may also allow for more hours of operation.[25] The Market Monitoring Unit objected to the settlement, explaining that it did not enhance clean air, participation by demand side resources in the organized markets nor reliability.[26] If approved, the settlement would require the EPA Administrator to take final action on the rules by December 14, 2012, and if the EPA promulgates in final form an amendment to the RICE Rules that includes changes substantially the same as those agreed upon, then Petitioners will dismiss their appeal.

Greenhouse Gas Regulation

On April 2, 2007, the U.S. Supreme Court overruled EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[27] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[28]

The EPA determined that in order to regulate greenhouse gas emissions, it would need to develop a different standard for determining major sources that require permits to emit greenhouse gases as opposed to other pollutants. Application of the prevailing 100 or 250 tons per year (tpy) annual emissions rates would overwhelm the capabilities of state permitting authorities and impede the ability to construct or modify regulated facilities.[29]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[30] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011, referring to each phase as a step. Affected facilities will be required to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tpy CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[31]

On July 1, 2011, step 2 expanded the rule to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[32] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[33]

On February 3, 2012, the EPA proposed step 3.[34] This proposed rule would leave the step 2 thresholds unchanged. Step 2 allows permitting on a plant wide basis so that changes at a facility that do not violate the plant wide limits do not require additional permitting.[35]

23 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295 , codified at 40 CFR Part 60 Subpart JJJJ.

24 See EnerNOC, et al v. EPA, No. 10-1090 and No. 10-1336.

25 Proposed Settlement Agreement, EPA Docket No. RL-9615-8, 77 Fed. Reg. 282 (January 4, 2012).

26 See In the Matter of: EnerNOC, Inc., et al., Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

27 Massachusetts v. EPA, 549 U.S. 497.

28 See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66496, 66497 (December 15, 2009).

29 EPA, Proposed Rule, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations, Docket No. EPA-HQ-2009-0517 (February 24, 2012) at 6-7 (Step 3 Tailoring Rule).

30 EPA, Final Rule, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Docket No. EPA-HQ-OAR-2009-0517, 75 Fed. Reg. 31514.

31 Id. at 31516.

32 Id.

33 Id. at 31520.

34 Step 3 Tailoring Rule.

35 Id. at 8.

Step 2 also allows for sources to obtain status as "synthetic minor sources," and avoid status as a regulated major source, on the basis of its voluntary acceptance of enforceable emissions limits.[36] For example, a generating unit that would be a major resource if it operated every hour of the year could become a synthetic minor resource by accepting enforceable emissions limits based on its practical physical and operational limitations.[37]

On December 23, 2010, the EPA entered a settlement agreement to resolve the States and other litigants request for performance standards and emission guidelines for GHG emissions for new and significantly modified sources, as provided under Sections 111(b) and (d) of the CAA. The EPA has missed both its original and extended agreed upon deadlines to issue a proposed rule, July 26, 2011, and September 30, 2001, respectively. The EPA has not released a revised schedule. A proposed rule is expected to amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.[38]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the Clean Water Act (CWA).[39] A settlement in a Federal Court obligates the EPA to issue a final rule no later than July 27, 2012.[40]

This rule seeks to protect aquatic life from from being trapped on the screens that cover water intake structures over the cooling system at a generating facility (impingement) or drawn into the cooling system (entrainment).

The EPA would study facilities that draw 125 MGD or more to evaluate, in a process open to the public, the need for site specific controls to prevent entrainment, and if there is a need, determine those controls.

The rule would require new or upgraded units to include or add technology equivalent to closed cycle cooling.

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules, which apply to annual and seasonal emissions, affect units based on total annual or seasonal emissions. Units with relatively low capacity factors have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules. The New Jersey Department of Environmental Protection estimates that regulations targeting such units have the potential for region wide emission reductions of 1–2 ppb and greater localized reductions.[41]

New Jersey has addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as "High Electric Demand Days" or "HEDD," and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on HEDD. New Jersey's HEDD rule,[42] which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBTU and lack identified emission control technologies.[43]

New Jersey's HEDD rule will be implemented in two phases. For the first and currently effective phase, owners/operators of HEDD units have prepared a 2009 HEDD Emission Reduction Compliance Demonstration Protocol (HEDD Protocol) and obtained the approval of the New Jersey Department of Environmental Protection. A HEDD Protocol may include the following measures: installation of emissions controls at the HEDD unit or a non-HEDD unit; run-time limitations; commitment to use natural gas on HEDD units if dual fueled;

36 Id.
37 See Id.
38 See 40 CFR Part 60.
39 EPA, National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).
40 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, Et Al. V. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010.
41 See Tonalee Carlson Key, New Jersey Department of Environmental Protection, "Electric Generation on High Electric Demand Days," presentation at annual public hearing (April 1, 2009) at 11–12. This document may be accessed at: <http://www.state.nj.us/dep/cleanair/hearings/powerpoint/09_electric_gen.ppt>.
42 N.J.A.C. § 7:27–19.
43 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

implementation of energy efficiency, demand response or renewable energy measures; or other approved measures. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports. The second phase involves performance standards applicable after May 1, 2015. New, reconstructed or modified turbines must comply with State of the Art (SOTA), Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT) standards, as applicable. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan describing how each owner/operator intended to comply with the 2015 HEDD maximum NO_x emission rates. On February 8, 2012, the Governor of New Jersey announced that no extension beyond the 2015 deadline would be granted.

Table 7-2 shows the HEDD emissions limits applicable to each unit type.

Table 7-2 HEDD maximum NOx emission rates[44]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[45] After December 31, 2011, the State of New Jersey will no longer participate in the RGGI program.

Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

Since September 25, 2008, a total of 14 auctions have been held for 2009–2011 compliance period allowances, and 12 auctions have been held for 2012–2014 compliance period allowances.

Table 7-3 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period[46]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000

Table 7-3 shows the RGGI CO_2 auction clearing prices and quantities for the ten 2009-2011 compliance period auctions held as of the end of calendar year 2011. The

44 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

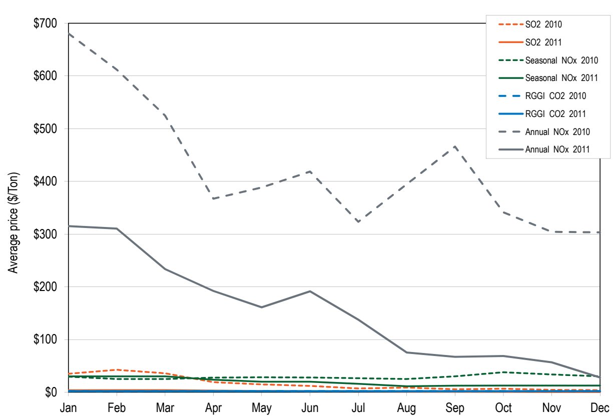
45 A similar regional initiative has organized under the Western Climate Initiative, Inc. (WCI). The first mover is the California Air Resources Board (ARB), which has organized a cap and trade program that it will implement starting in 2012. That program will be coordinated with other U.S. states and Canadian provinces participating in WCI. One such participant, Quebec, adopted cap and trade rules on December 15, 2011. British Columbia, Manitoba and Ontario are also expected to coordinate cap and trade policies through WCI.

46 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed January 3, 2012).

weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2011 calendar year was $2.56. Auction prices within the 2011 calendar year for the 2009-2011 compliance period were $1.89 throughout the year. This price, $1.89 per allowance, is the current price floor for RGGI auctions, as determined in the first RGGI auction. The average 2011 spot price for a 2009-2011 compliance period allowance was $1.91 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in March at $1.96 per ton and declining to $1.89 per ton during September through November, a price equal to the the auction's price floor of $1.89.

Figure 7-1 shows average, daily settled prices for NOx and SO_2 emissions within PJM. In 2011, seasonal NOx prices were 50.8 percent lower than in 2010. SO_2 prices were 87.3 percent lower in 2011 than in 2010. Figure 7-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

Figure 7-1 Spot monthly average emission price comparison: 2010 and 2011



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2011, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 8.30 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2021. As shown in Table 7-4, New Jersey will require 22.5 percent of load to be served by renewable resources, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction, for example, Illinois requires only utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not recognized as part of PJM markets. Revenues from RECs markets are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources", which includes resources such as wind, solar, and run-of-river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the Generation Attribute Tracking System (GATS), which is used by many jurisdictions to track these renewable energy credits. The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of wholesale energy markets.

Table 7-4 Renewable standards of PJM jurisdictions to 2021[47,48]

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana			4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

Table 7-5 Solar renewable standards of PJM jurisdictions to 2021

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Solar Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 7-4 but must be met by solar RECs only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2021.[49] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2011, the most stringent standard in PJM was New Jersey's, requiring 0.31 percent of load to be served by solar resources. As Table 7-5 shows, by 2021, the most stringent standard will be Delaware's which requires at least 2.5 percent of load to be served by solar.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 7-6 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, starting at 4.50 percent in 2011 and escalating to 14.25 percent in 2021. Maryland, New Jersey, Pennsylvania[50], and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits. North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards, while New Jersey requires 2,518 GWh of solar generation by 2021 (Table 7-6).

PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an

47 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

48 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

49 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

50 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

Table 7-6 Additional renewable standards of PJM jurisdictions to 2021

Jurisdiction		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste		0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)		170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $675 per MWh. Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the renewable portfolio standard be met through alternative compliance payments. Table 7-7 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

Table 7-8 shows generation by jurisdiction and renewable resource type in 2011. This includes only units that would

Table 7-7 Renewable alternative compliance payments in PJM jurisdictions: 2011

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	Voluntary standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 7-8 Renewable generation by jurisdiction and renewable resource type (GWh): Calendar year 2011

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	61.2	0.0	0.0	0.0	0.0	0.0	0.0	61.2	122.4
Indiana	0.0	0.0	41.8	0.0	0.0	0.0	2,640.6	2,682.4	2,682.4
Illinois	148.9	0.0	0.0	0.0	7.6	0.0	5,450.5	5,599.4	5,607.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	104.6	0.0	2,553.5	0.0	913.5	0.0	311.8	2,969.9	3,883.4
Michigan	29.0	0.0	63.3	0.0	0.0	0.0	0.0	92.4	92.4
New Jersey	347.9	541.0	24.4	50.9	1,403.5	0.0	9.7	432.9	2,377.4
North Carolina	0.0	0.0	383.9	0.0	0.0	0.0	0.0	383.9	383.9
Ohio	120.0	0.0	120.9	1.3	0.0	0.0	225.0	467.2	467.2
Pennsylvania	887.6	1,650.8	3,416.7	3.4	1,715.9	11,047.7	1,784.9	6,092.6	20,507.0
Tennessee	0.0	0.0	0.0	0.0	329.0	0.0	0.0	0.0	329.0
Virginia	183.1	4,693.9	709.7	0.1	1,190.1	0.0	0.0	892.9	6,776.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	6.1	0.0	1,078.2	0.0	0.0	1,062.2	1,138.7	2,222.9	3,285.1
Total	1,888.6	6,885.7	8,392.3	55.7	5,559.6	12,109.9	11,561.1	21,897.6	46,452.8

Table 7-9 PJM renewable capacity by jurisdiction (MW), on December 31, 2011[51]

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	60.0	24.5	129.0	31.9	0.0	590.0	0.0	109.0	0.0	120.0	1,064.4
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	119.7	191.1	0.0	7.5	808.8
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	3,939.7	25.8	25.0	209.0	0.0	178.0	1.1	0.0	0.0	500.0	4,878.6
Pennsylvania	35.0	222.3	2,370.7	0.0	1,505.0	672.6	3.0	263.0	1,473.9	865.0	7,410.4
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	114.9	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,471.9
West Virginia	500.0	2.0	0.0	0.0	0.0	244.0	0.0	0.0	130.0	663.5	1,539.5
PJM Total	4,534.7	552.8	4,440.0	272.8	5,493.0	2,481.7	123.9	943.1	1,603.9	5,339.1	25,784.9

Table 7-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS[52,53] (MW), on December 31, 2011

Jurisdiction	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	25.8	0.0	0.1	25.9
Illinois	4.0	99.2	0.0	0.0	0.0	10.7	0.0	302.5	416.4
Indiana	0.0	38.6	0.0	679.1	0.0	0.7	0.0	0.0	718.4
Kentucky	2.0	16.0	0.0	0.0	0.0	0.4	88.0	0.0	106.4
Maryland	0.0	7.0	0.0	0.0	0.0	38.1	0.0	0.0	45.1
Michigan	0.0	1.6	0.0	0.0	0.0	0.2	28.0	0.0	29.8
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	39.9	0.0	0.0	23.3	414.1	0.0	0.2	477.5
New York	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	225.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	227.1
Ohio	1.0	37.3	52.6	45.0	0.0	28.0	109.3	10.4	283.6
Pennsylvania	0.2	8.4	4.8	85.5	0.3	115.2	0.0	49.2	263.6
Virginia	12.5	14.8	0.0	0.0	0.0	4.3	318.1	0.0	349.7
West Virginia	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.5
District of Columbia	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	3.1
Total	357.5	262.8	57.4	809.6	23.6	644.0	588.0	508.4	3,251.3

qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 11,561.1 GWh of 21,897.6 Tier I GWh, or 53.0 percent, in the PJM footprint. As shown in Table 7-8, 46,452.8 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 47.1 percent.

Table 7-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[54] This analysis includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. Pennsylvania has the largest amount of renewable capacity in PJM, 7,410.4 MW, or 28.7 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 119.7 MW, or 96.7 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 2,998.1 MW, or 56.2 percent of the total wind capacity.

Table 7-10 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not PJM units. This includes solar capacity of 644.1 MW of which

51 The correct value as of December 31, 2010 for Pumped Storage Hydro capacity in Pennsylvania was 1,505 MW, rather than the listed 2,575 MW.

52 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.

53 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 01, 2012).

54 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

414.1 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 7-10 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 82,039.8 MW of coal steam capacity in PJM, 52,953.2 MW of capacity, 64.5 percent, has some form of FGD technology. Table 7-11 shows emission controls by unit type, of fossil fuel units in PJM.

Table 7-11 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2011

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	52,953.2	29,086.6	82,039.8	64.5%
Combined Cycle	0.0	26,905.7	26,905.7	0.0%
Combustion Turbine	0.0	30,620.8	30,620.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	0.0	9,478.0	9,478.0	0.0%
Total	52,953.2	96,457.6	149,410.8	35.4%

NOx emission controlling technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NOx controls. Of current fossil fuel units in PJM, 135,029.6 MW, or 90.4 percent, of 149,410.8 MW of capacity in PJM, have emission controls for NOx. Table 7-12 shows NOx emission controls by unit type of fossil fuel units in PJM. While most units in PJM have NOx emission controls, many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future NOx compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 7-12 NOx emission controls by unit type (MW), as of December 31, 2011

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	79,417.0	2,622.8	82,039.8	96.8%
Combined Cycle	26,169.6	736.1	26,905.7	97.3%
Combustion Turbine	24,952.8	5,668.0	30,620.8	81.5%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	4,490.2	4,987.8	9,478.0	47.4%
Total	135,029.6	14,381.2	149,410.8	90.4%

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 80,405.8 MW, 98.0 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-13 shows particulate emission controls by unit type of fossil fuel units in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which many coal steam units have not installed.

Table 7-13 Particulate emission controls by unit type (MW), as of December 31, 2011

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	80,405.8	1,634.0	82,039.8	98.0%
Combined Cycle	0.0	26,905.7	26,905.7	0.0%
Combustion Turbine	0.0	30,620.8	30,620.8	0.0%
Diesel	0.0	366.5	366.5	0.0%
Non-Coal Steam	3,047.0	6,431.0	9,478.0	32.1%
Total	83,452.8	65,958.0	149,410.8	55.9%

Wind Units

Table 7-14 shows the capacity factor of wind units in PJM. In 2011, the capacity factor of wind units in PJM was 28.9 percent. Wind units that were capacity resources had a capacity factor of 29.7 percent and an installed capacity of 3,930 MW. Wind units that were classified as energy only had a capacity factor of 23.9 percent and an installed capacity of 1,410 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 7-14 Capacity[55] factor[56] of wind units in PJM: Calendar year 2011

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	23.9%	NA	120,242	1,410
Capacity Resource	29.7%	169.2%	355,369	3,930
All Units	28.9%	169.2%	475,611	5,339

Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-15 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 935.5 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 1,973 separate five minute intervals, or 1.88 percent of all intervals. On average, 2,270.9 MW of wind were offered daily. Overall, wind units were marginal in 8,848 separate five minute intervals, or 8.42 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out-of-market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-15 Wind resources in real time offering at a negative price in PJM: Calendar year 2011

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	935.5	1,973	1.88%
All Wind	2,270.9	8,848	8.42%

Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in November, February and April, and lowest in June and July. The highest average hour, 2,350.4 MW, occurred in December, and the lowest average hour, 354.9 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 7-2 Average hourly real-time generation of wind units in PJM: Calendar year 2011

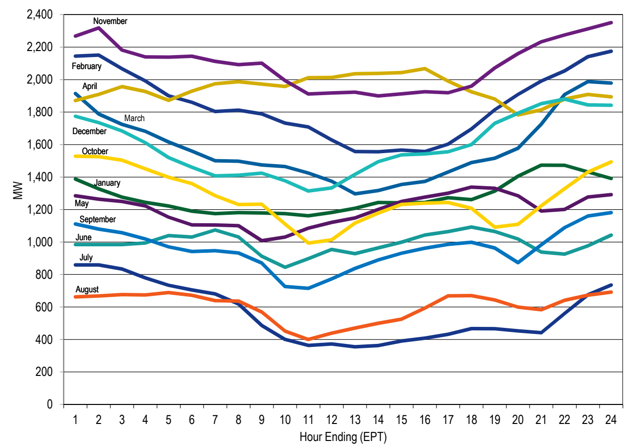


Table 7-16 shows the generation and capacity factor of wind units in each month of 2011. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 42.4 percent in February, and the lowest capacity factor was 12.2 percent in July, a difference of 30.2 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2011, and are included in this analysis as they were added.

Table 7-16 Capacity factor of wind units in PJM by month, 2010 and 2011[57]

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	971,942.0	35.9%	950,441.9	29.7%
February	736,663.6	28.9%	1,237,813.0	42.4%
March	853,590.0	30.3%	1,175,567.0	36.4%
April	1,001,447.6	36.6%	1,399,217.0	44.7%
May	730,087.9	25.9%	893,485.1	27.6%
June	492,344.0	17.7%	713,713.8	22.0%
July	396,754.7	13.7%	416,695.8	12.2%
August	344,015.5	11.6%	447,575.2	13.1%
September	733,193.7	23.0%	689,962.6	20.9%
October	1,042,735.7	31.1%	946,406.3	26.3%
November	1,127,306.0	34.0%	1,507,766.4	41.8%
December	1,159,478.3	33.8%	1,182,421.6	31.5%
Annual	9,589,559.0	27.4%	11,561,065.8	28.9%

55 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource.

56 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

57 Capacity factor shown in Table 716 is based on all hours in January through September, 2011.

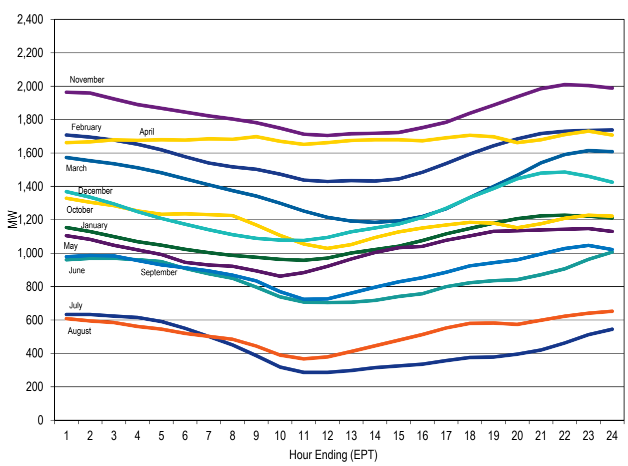
Table 7-17 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load for on peak and off peak periods. The on peak winter capacity factor was 32.4 percent while the on peak summer capacity factor was 18.7 percent. The off peak winter capacity factor was 3.6 percentage points higher than during the on peak period, while the off peak summer capacity factor was 0.4 percentage points lower than during the on peak period.

Table 7-17 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): Calendar year 2011

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.4%	42.1%	18.7%	32.3%	27.3%
	Average Wind Generation	1,475.0	2,003.5	869.3	1,551.6	1,266.4
	Average Load	86,939.1	75,551.5	99,674.0	83,896.3	91,190.4
Off-Peak	Capacity Factor	36.0%	44.9%	18.3%	37.1%	29.4%
	Average Wind Generation	1,646.3	1,874.6	853.7	1,782.2	1,366.6
	Average Load	75,243.8	62,156.7	78,079.9	69,313.3	74,626.6

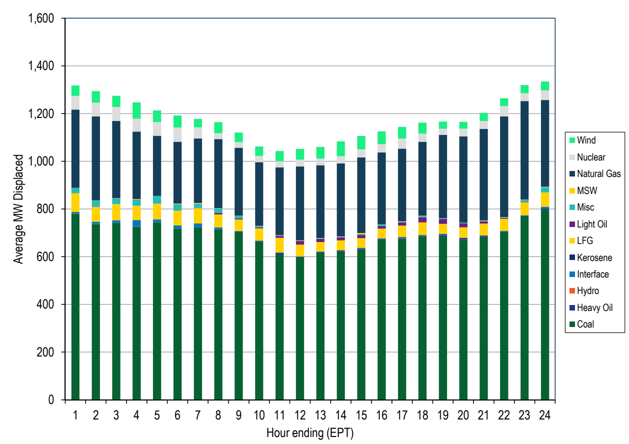
Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 7-3 shows the average hourly day-ahead time generation of wind units in PJM, by month.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: Calendar year 2011



Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 7-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2011. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2011. Wind output varies daily, and on average is about 292 MW lower from peak average output (2300 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the displaced fuel at times when wind resources were on the margin. In effect this means that there was no displacement for those hours.

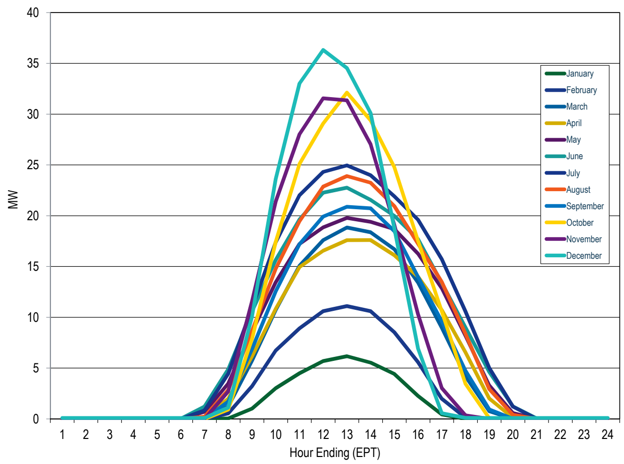
Figure 7-4 Marginal fuel at time of wind generation in PJM: Calendar year 2011



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 7-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in July, the month with the most daylight hours. The highest average hour, 35.5 MW, occurred in December, primarily due to increases in solar capacity throughout calendar year 2011. In general, solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: Calendar year 2011



Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Overview

Interchange Transaction Activity

- **American Transmission System, Inc. (ATSI) Integration.** On June 1, 2011, at 0100, First Energy's American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. The integration also resulted in the elimination of the MICHFE Interface Pricing Point, reducing the total number of real-time interface pricing points from 17 to 16.[1]
- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. In 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -813.5 GWh compared to -805.1 GWh for the calendar year 2010.[2] Gross monthly import volumes averaged 3,437.8 GWh compared to 3,495.6 GWh in 2010 while gross monthly exports averaged 4,251.3 GWh compared to 4,300.6 GWh for the calendar year 2010.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June and December, and a net exporter of energy in the remaining months. In 2010, PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December, and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 548.0 GWh compared to -539.2 GWh for the calendar year 2010. Gross monthly import volumes averaged 10,751.5 GWh compared to 7,341.6 GWh for the calendar year 2010 while gross monthly exports averaged 10,203.5 GWh compared to 7,880.8 GWh for the calendar year 2010.

  The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. In all months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange.
- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2011, gross imports in the Day-Ahead Energy Market were 313 percent of gross imports in the Real-Time Energy Market (210 percent for the calendar year 2010). In 2011, gross exports in the Day-Ahead Energy Market were 240 percent of gross exports in the Real-Time Energy Market (183 percent for the calendar year 2010). In 2011, net interchange was 6,576.2 GWh in the Day-Ahead Energy Market and -9.761.8 GWh in the Real-Time Energy Market compared to -6,470.0 GWh in the Day-Ahead Energy Market and -9,661.0 GWh in the Real-Time Energy Market for the calendar year 2010.
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 2011, there were net exports at 14 of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 67.7 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, PJM/MidAmerican Energy Company (MEC) with 19.5 percent, PJM/Neptune (NEPT) with 14.0 percent and PJM/Cinergy Corporation (CIN) with 12.2 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 39.4 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interfaces had net imports, with two importing interfaces accounting for 74.0 percent of the total

1 The tables and figures within this section continue to show that the FE Interace and the MICHFE Interface Pricing Points existed in June 2011, to account for the single hour in June where FE was still an external interface.

2 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 55.6 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18.4 percent.[3]

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 2011, there were net exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.[4] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 84.7 percent of the total net exports: PJM/MISO with 57.5 percent, PJM/NYIS with 16.6 percent and PJM/NEPTUNE (NEPT) with 10.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 29.8 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total net imports: PJM/SouthIMP with 40.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 38.0 percent of the net import volume.[5]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at 13 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.7 percent, PJM/Neptune (NEPT) with 20.4 percent and PJM/Linden (LIND) with 14.4 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 32.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95.5 percent of the total net imports: PJM/OVEC with 43.0 percent, PJM/Michigan Electric Coordinated System (MECS) with 31.2 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 21.3 percent.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 80.3 percent of the total net exports: PJM/SouthEXP with 39.7 percent, PJM/NEPTUNE (NEPT) with 26.7 percent, and PJM/Southeast with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 13.9 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 26.7 percent and PJM/LINDEN with 4.7 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eleven PJM interface pricing points had net imports, with three importing interface pricing points accounting for 68.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.9 percent, PJM/SouthIMP with 17.8 percent and PJM/NYIS with 14.0 percent of the net import volume.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $32.32 while the MISO LMP at the border was $34.01, a difference of $1.69. The average hourly flow during the calendar year 2011 was -1,570 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 45 percent of hours in 2011.

- **PJM and New York ISO Interface Prices.** In 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices

3 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

4 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

5 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (MICHFE and NCMPAEXP).

between PJM and the NYISO. In 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the PJM/NYISO border was $43.88 while the NYISO LMP at the border was $42.33, a difference of $1.55. The average hourly flow during the calendar year 2011 was -626 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 52 percent of the hours in 2011.

- **Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Neptune Interface was $48.20 while the NYISO LMP at the Neptune Bus was $54.11, a difference of $5.91. The average hourly flow during the calendar year 2011 was -493 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours in 2011.
- **Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[6] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. In 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Linden Interface was $47.19 while the NYISO LMP at the Linden Bus was $48.70, a difference of $1.51. The average hourly flow during the calendar year 2011 was -122 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 61 percent of the hours in 2011.
- **Hudson DC Line.** The Hudson direct current (DC) line will be a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection will be a submarine AC cable system. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). The Hudson DC line is expected to be in service late in 2012.

Operating Agreements with Bordering Areas

- **PJM and MISO Joint Operating Agreement.**[7] The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during 2011. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately.

6 See PJM Interconnection, L.L.C, Docket No. ER11-3250-000 (March 31, 2011).

7 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx. (Accessed March 1, 2012)

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[8] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and NYISO began discussion of a market based congestion management protocol. On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that include a market to market process.[9]

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**[10] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of MISO and PJM and the service territory of TVA. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement continued to be in effect in 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[11] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). The parties meet on a yearly basis, and, in 2011, there were no developments. However, on May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[12] The agreement remained in effect in 2011.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[13] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement remained in effect in 2011.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** In 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[14] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange)

8 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf>. (Accessed March 1, 2012)

9 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30,2011).

10 See "Congestion Management Process (CMP) Master," (May 1, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx>. (Accessed March 1, 2012)

11 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx>. (Accessed March 1, 2012)

12 PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc., Docket No. ER11-3637-000 (May 25, 2011)

13 See "Adjacent Reliability Coordinator Coordination Agreement," (May 23, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> . (Accessed March 1, 2012)

14 See 111 FERC ¶ 61,228 (2005).

for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces.

Loop flow can arise from transactions scheduled into, out of, through or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh or 7.1 percent, an increase from 5.2 percent for the calendar year 2010. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2011, PJM issued 62 TLRs of level 3a or higher. Of the 62 TLRs issued, 34 events were TLR level 3a, and the remaining 28 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 62 TLRs in 2011, compared to 110 during the calendar year 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would otherwise require the need for higher level TLRs.

- **Up-To Congestion.** Following the elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions significantly increased. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011, compared to an average of 4,269 bids per day, with an average cleared volume of 310,660 MWh per day, for the calendar year 2010.

  The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** Total uncollected congestion charges in 2011 were -$20,955, compared to $3.3 million for the calendar year 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in 2011. The fact that there was a total negative congestion collection in 2011, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[15] These modifications are currently being evaluated by PJM. It is expected

15 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

that implementation of these changes will occur by the end of the second quarter 2012.

- **Spot Import.** In 2009, the MMU and PJM jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it.

  In 2011, PJM suggested including a utilization factor in the ATC calculation for all non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

- **Real-Time Dispatchable Transactions.** Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

  Dispatchable transactions were initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits.

  Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were $1.3 million, a decrease from $23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011.

  The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[16] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.

- **Internal Bilateral Transactions.** In the third quarter of 2011, it was discovered that a number of companies had been utilizing internal bilateral transactions to inappropriately reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with their PJM Day-Ahead Market positions. This issue is currently being addressed at FERC and through the PJM stakeholder process.[17]

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market

16 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> . (July 13, 2011)

17 DC Energy, LLC and DC Energy Mid-Atlantic, LLC v. PJM Interconnection, L.L.C., Docket No. EL12-8-000 (October 28, 2011).

areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

On June 1, 2011, at 0100, the American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. Additionally, following the ATSI integration, the MICHFE Interface Pricing Point was eliminated, reducing the total number of real-time interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during 2011, including evolving transaction patterns, economics and issues. In 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period.

A large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 67.7 percent of the total real-time net exports and two interfaces accounted for 74.0 percent of the real-time net import volume. Three interfaces accounted for 60.5 percent of the total day-ahead net exports and three interfaces accounted for 95.5 percent of the day-ahead net import volume.

A large share of both import and export activity also occurred at a small number of interface pricing points. Three interface pricing ponts accounted for 84.7 percent of the total real-time net exports and two interfaces accounted for 78.7 percent of the real-time net import volume. Three interface pricing points accounted for 80.3 percent of the total day-ahead net exports and three interface pricing points accounted for 68.7 percent of the day-ahead net import volume.

In 2011, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for many hours, 55 percent between PJM and MISO and 48 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Detailed Recommendations

- **The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.**
  - The MMU recommends that the up-to congestion transaction product be eliminated. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. At the PJM Market Implementation Committee, held on February 17, 2012, the PJM stakeholders agreed to form a task force to address this recommendation.
  - The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding. The use of specific buses is equivalent to creating a scheduled transaction to a specific

point which will not be matched by the actual corresponding power flow.

- The MMU recommends that PJM perform a regular assessment of the mappings of external balancing authorities associated with the interface pricing points, and modifiy as necessary to reflect current system topology in order to ensure that transactions are priced based on the actual flows that they create on the transmission system.
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.
- The MMU recommends that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[18] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[19] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[20] These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends that the Enhanced Energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced.[21]
- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.[22] On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.[23] As of December 31, 2011, the Commission had not made a final rulemaking decision on this proposal.
- The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing

18 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

19 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> . (July 13, 2011)

20 See "Meeting Minutes" Minutes from PJM's MIC meeting , <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> . (May 16, 2011)

21 See "PJM Manual 41: Managing Interchange," Revision 03 (November 24, 2008), External Transaction Minimum Duration Requirement.

22 See 135 FERC ¶ 61,052 (2011).

23 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

authorities be reviewed, and modified as necessary, to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles. In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process.

— The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to a single LMP market. PJM is engaged in preliminary discussions with both MISO and NYISO on interface pricing.

— The MMU recommends that the PJM and MISO JOA be modified to eliminate payments between RTOs when such payments would result from the failure of generating units to respond to appropriate pricing signals.

— The MMU recommends that the grandfathered Southeast and Southwest Interface pricing agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. These agreements expired on January 31, 2012 and have not been renewed. The MMU recommends that PJM not enter into any such special pricing agreements.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net importer of energy in the Real-Time Energy Market in January, and an exporter of energy in the remaining months of 2011 (Figure 8-1).[24,25]

The total 2011 real-time net interchange of -9,761.8 GWh was greater than net interchange of -9,661.0 GWh in 2010. The peak month in 2011 for net exporting interchange was September, -1,855.3 GWh; in 2010 it had been September, -1,778.1 GWh. Gross monthly import volumes averaged 3,437.8 GWh compared to 3,495.6 GWh in 2010, while gross monthly exports averaged 4,251.3 GWh compared to 4,300.6 GWh for the calendar year 2010.

In 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June and December, and a net exporter of energy in the remaining months (Figure 8-1). In 2010, PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December, and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 548.0 GWh compared to -539.2 GWh for the calendar year 2010. Gross monthly import volumes averaged 10,751.5 GWh compared to 7,341.6 GWh for the calendar year 2010 while gross monthly exports averaged 10,203.5 GWh compared to 7,880.8 GWh for the calendar year 2010.

The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. In all months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports. Figure 8-1 shows the correlation between net up-to congestion transactions and the net Day-Ahead Market interchange. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011, compared to an average of 4,269 bids per day, with an average cleared volume of 310,660 MWh per day, for the calendar year 2010.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets.[26] In 2011, gross

24 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

25 The interchange values shown in Figure 8-1 and Figure 8-2, and Table 8-1 through Table 8-12 do not include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in these figures and tables does not match the "Net Scheduled" values shown in Table 8-16.

26 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges based on the differences between the transaction MW in the Day-Ahead and Real-Time Markets.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: Calendar year 2011

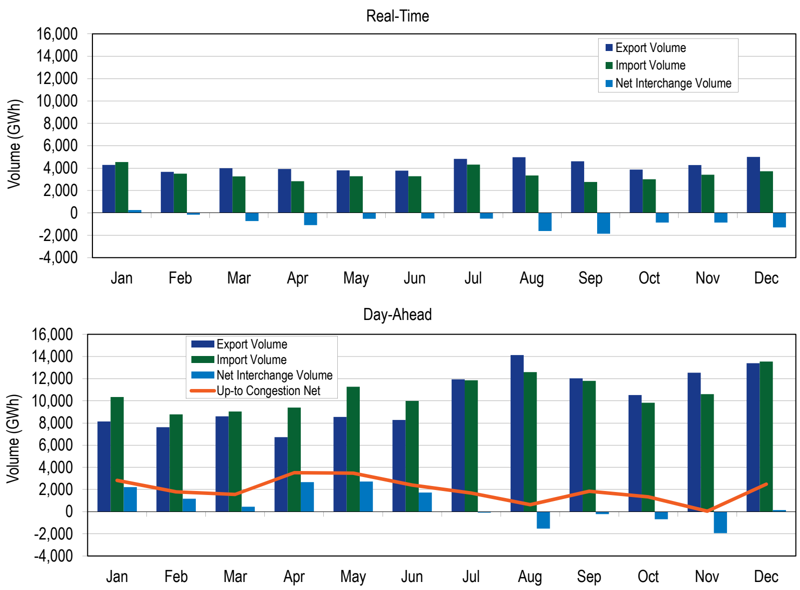
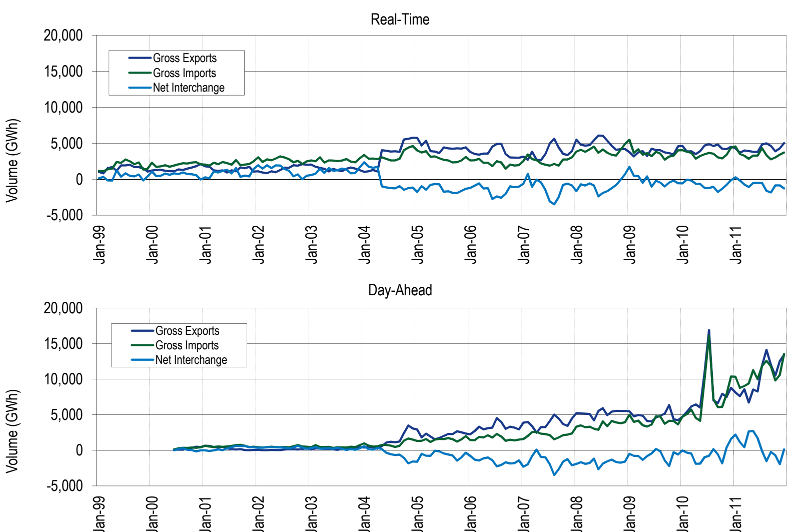


Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through December, 2011



imports in the Day-Ahead Energy Market were 313 percent of the Real-Time Energy Market's gross imports (210 percent for the calendar year 2010), gross exports in the Day-Ahead Energy Market were 240 percent of the Real-Time Energy Market's gross exports (183 percent for the calendar year 2010). In 2011, net interchange was 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market compared to -6,470.0 GWh in the Day-Ahead Energy Market and -9,661.0 GWh in the Real-Time Energy Market for the calendar year 2010.

Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2011. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. However, due to the increase in up-to congestion transactions in late 2010, PJM has been a net importer of energy in the Day-Ahead Market in eight months in 2011.

Real-Time Interface Imports and Exports

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

In the Real-Time Energy Market, scheduled imports and exports are determined by the market path (the transmission path a market participant selects from the original source to the final sink). These scheduled flows are measured at each of PJM's interfaces with

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(122.7)	(29.5)	(43.3)	(29.1)	(76.8)	(78.7)	(81.0)	(81.5)	(51.5)	(8.2)	(13.7)	(33.6)	(649.7)
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0	2.4
DUK	(25.6)	218.8	(17.1)	12.8	34.7	(36.8)	33.9	(289.3)	(132.1)	(53.4)	(74.4)	57.7	(271.0)
EKPC	(61.4)	(10.1)	5.6	135.0	41.4	106.4	107.0	100.7	80.4	(70.6)	28.2	11.0	473.6
LGEE	392.9	385.8	314.6	200.0	241.7	322.1	303.1	246.6	327.7	416.9	368.5	361.6	3,881.4
MEC	(426.0)	(403.2)	(462.3)	(463.2)	(478.5)	(456.3)	(675.5)	(565.8)	(616.7)	(517.7)	(471.6)	(479.0)	(6,015.6)
MISO	(77.5)	(388.9)	(744.3)	(1,131.2)	(495.8)	(675.9)	(576.1)	(752.7)	(1,187.3)	(411.5)	(961.4)	(1,397.2)	(8,799.9)
ALTE	(116.1)	(128.3)	(76.0)	(4.5)	(7.6)	(105.7)	(210.6)	(193.5)	(378.8)	(467.0)	(722.0)	(1,015.2)	(3,425.3)
ALTW	(30.9)	(14.5)	(28.6)	(49.9)	(68.8)	(83.2)	(119.3)	(83.2)	(249.3)	(28.4)	(53.6)	(64.9)	(874.5)
AMIL	(2.9)	45.5	14.3	8.6	37.8	(17.5)	(34.8)	(101.8)	(120.2)	6.2	(10.5)	49.2	(126.2)
CIN	(85.6)	(314.7)	(454.6)	(713.8)	(242.7)	(423.9)	(338.1)	(113.3)	(376.2)	0.7	(298.9)	(410.5)	(3,771.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(250.2)	(250.9)	0.2	0.0	0.0	0.0	0.0	0.0	0.0	(554.2)
IPL	21.8	3.5	8.8	(3.4)	11.0	(12.8)	(60.6)	(111.3)	(30.9)	48.8	(12.1)	(18.0)	(155.2)
MECS	193.0	190.8	112.6	33.2	160.1	128.8	413.2	218.8	223.3	421.4	433.9	400.2	2,929.4
NIPS	(114.3)	(51.0)	(69.7)	(72.6)	(53.7)	(71.9)	(80.0)	(62.6)	(42.8)	(29.9)	(69.4)	(67.3)	(785.1)
WEC	(92.3)	(76.4)	(92.1)	(78.6)	(81.0)	(89.9)	(145.9)	(305.7)	(212.5)	(363.3)	(228.9)	(270.6)	(2,037.2)
NYISO	(1,349.2)	(1,268.3)	(1,021.4)	(855.2)	(721.4)	(665.7)	(929.2)	(1,336.3)	(1,141.1)	(1,030.7)	(858.9)	(964.1)	(12,141.5)
LIND	(156.0)	(145.3)	(115.1)	(128.9)	(90.5)	(77.8)	(25.1)	(90.8)	(121.9)	(40.9)	(29.3)	(39.7)	(1,061.4)
NEPT	(404.2)	(370.6)	(375.6)	(284.6)	(379.5)	(235.7)	(365.0)	(450.8)	(307.0)	(381.7)	(325.4)	(436.6)	(4,316.8)
NYIS	(789.1)	(752.3)	(530.7)	(441.6)	(251.4)	(352.2)	(539.0)	(794.8)	(712.2)	(608.1)	(504.2)	(487.7)	(6,763.4)
OVEC	1,242.2	1,110.7	1,065.8	1,018.9	1,030.7	1,014.6	1,040.8	1,011.9	828.9	666.5	759.6	903.9	11,694.6
TVA	681.6	222.8	170.3	20.0	(98.5)	(36.7)	264.2	41.8	36.4	151.9	360.8	249.3	2,063.8
Total	254.3	(162.0)	(732.1)	(1,092.1)	(522.5)	(504.7)	(512.8)	(1,624.6)	(1,855.3)	(856.9)	(862.8)	(1,290.3)	(9,761.8)

neighboring balancing authorities. (See Table 8-13 for a list of active interfaces in 2011. Figure 8-3 shows the approximate geographic location of the interfaces.) In 2011, PJM had 21 interfaces with neighboring balancing authorities.[27] The Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are interfaces between PJM and the NYISO. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Market is shown by interface for 2011 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for the calendar year 2011, there were net exports at 14 of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 67.7 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, PJM/MidAmerican Energy Company (MEC) with 19.5 percent, PJM/Neptune (NEPT) with 14.0 percent and PJM/Cinergy Corporation (CIN) with 12.2 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 39.4 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interfaces had net imports, with two importing interfaces accounting for 74.0 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 55.6 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18.4 percent.[28]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[29] OVEC itself does not serve load, and therefore does not generally import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange volume.

27 The number of interfaces with PJM was reduced to 20 when FE was removed as an interface coincident with the integration of ATSI into the PJM footpring on June 1, 2011.

28 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

29 See "Ohio Valley Electric Corporation: Company Background." <http://www.ovec.com/OVECHistory.pdf>. (Accessed March 1, 2012).

Table 8-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.2	1.5	0.8	2.8	7.5	13.4	5.2	2.4	1.1	6.2	0.6	1.6	43.2
CPLW	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0	2.4
DUK	271.7	309.8	186.2	208.2	197.7	184.4	299.8	121.8	103.3	190.6	258.6	276.4	2,608.7
EKPC	31.7	46.5	41.0	143.3	85.5	112.3	116.7	110.3	85.9	36.2	32.3	21.6	863.2
LGEE	393.0	386.3	324.1	233.6	250.3	334.9	322.7	268.5	328.3	420.1	373.5	364.6	3,999.8
MEC	53.2	30.8	19.1	0.0	0.0	0.0	0.0	0.0	6.0	5.3	0.5	0.0	115.0
MISO	1,141.4	833.9	736.6	409.5	718.2	542.8	998.2	714.4	599.1	876.8	944.6	1,113.9	9,629.4
ALTE	0.0	0.0	0.0	0.0	0.0	0.2	1.6	0.0	0.0	0.0	0.0	0.0	1.8
ALTW	0.0	0.0	0.0	0.0	0.0	0.9	0.0	0.6	0.0	0.0	0.0	0.0	1.5
AMIL	23.9	68.0	42.2	26.0	55.4	37.8	85.2	75.0	7.3	34.8	28.4	105.5	589.5
CIN	400.0	270.3	315.2	180.8	348.0	260.0	359.4	344.9	261.8	292.7	361.9	467.5	3,862.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	55.5	71.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	906.6
IPL	25.4	4.8	15.3	5.6	19.3	66.9	89.3	37.1	39.6	71.5	70.7	94.0	539.5
MECS	250.9	270.3	241.4	141.4	224.3	176.7	460.7	256.8	289.3	477.8	479.6	442.7	3,711.8
NIPS	0.0	0.0	0.2	0.2	0.0	0.0	2.0	0.0	0.0	0.0	2.2	4.2	8.9
WEC	4.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.8	0.0	7.3
NYISO	681.0	534.7	646.6	686.3	911.1	975.9	1,144.4	961.2	731.3	652.8	637.5	713.9	9,276.6
LIND	0.0	0.0	0.0	0.0	0.0	14.3	51.7	27.9	10.6	19.1	17.6	24.4	165.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	686.3	911.1	961.6	1,092.6	933.3	720.7	633.7	619.9	689.5	9,111.0
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	1,063.6	1,013.7	834.7	666.6	782.2	929.2	11,798.5
TVA	725.7	255.5	212.0	128.8	79.7	92.0	360.3	152.7	69.8	159.0	387.0	294.9	2,917.4
Total	4,540.1	3,509.7	3,257.7	2,831.4	3,280.8	3,272.7	4,310.7	3,344.9	2,759.5	3,013.6	3,416.9	3,716.0	41,254.1

Table 8-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	123.0	31.0	44.1	31.9	84.3	92.2	86.1	83.9	52.5	14.4	14.3	35.2	692.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	195.5	163.0	221.2	265.9	411.1	235.5	244.1	333.0	218.7	2,879.6
EKPC	93.1	56.6	35.4	8.3	44.1	5.9	9.6	9.6	5.5	106.8	4.1	10.5	389.6
LGEE	0.1	0.4	9.5	33.6	8.6	12.8	19.6	21.9	0.6	3.2	5.0	3.0	118.4
MEC	479.2	434.1	481.3	463.2	478.5	456.3	675.5	565.8	622.7	523.0	472.1	479.0	6,130.6
MISO	1,218.8	1,222.8	1,480.9	1,540.7	1,214.1	1,218.8	1,574.2	1,467.1	1,786.4	1,288.3	1,906.1	2,511.1	18,429.2
ALTE	116.1	128.3	76.0	4.5	7.6	105.9	212.2	193.5	378.8	467.0	722.0	1,015.2	3,427.1
ALTW	30.9	14.5	28.6	49.9	68.8	84.1	119.3	83.8	249.3	28.4	53.6	64.9	876.0
AMIL	26.8	22.5	27.9	17.4	17.6	55.4	120.0	176.8	127.5	28.6	38.9	56.3	715.6
CIN	485.5	585.0	769.8	894.7	590.7	683.9	697.5	458.2	638.0	292.0	660.8	878.1	7,634.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	305.7	322.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	1,460.8
IPL	3.6	1.3	6.5	8.9	8.3	79.7	149.9	148.4	70.5	22.7	82.8	112.0	694.7
MECS	57.9	79.5	128.8	108.2	64.2	47.8	47.4	38.1	66.0	56.4	45.7	42.5	782.4
NIPS	114.3	51.0	69.9	72.8	53.7	71.9	82.0	62.6	42.8	29.9	71.5	71.5	794.0
WEC	96.8	76.4	92.1	78.6	81.0	89.9	145.9	305.7	213.5	363.3	230.7	270.6	2,044.5
NYISO	2,030.2	1,803.0	1,667.9	1,541.5	1,632.5	1,641.6	2,073.6	2,297.5	1,872.5	1,683.5	1,496.3	1,678.0	21,418.1
LIND	156.0	145.3	115.1	128.9	90.5	92.1	76.8	118.7	132.5	59.9	46.9	64.1	1,226.9
NEPT	404.2	370.6	375.6	284.6	379.5	235.7	365.0	450.8	307.0	381.7	325.4	436.6	4,316.8
NYIS	1,470.0	1,287.1	1,177.2	1,128.0	1,162.5	1,313.8	1,631.7	1,728.1	1,433.0	1,241.8	1,124.0	1,177.2	15,874.4
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	0.0	22.6	25.3	103.9
TVA	44.1	32.7	41.7	108.9	178.2	128.7	96.0	110.9	33.5	7.2	26.2	45.6	853.6
Total	4,285.8	3,671.8	3,989.8	3,923.5	3,803.3	3,777.4	4,823.4	4,969.6	4,614.9	3,870.5	4,279.7	5,006.3	51,015.9

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which imports or exports will flow.[30] An interface pricing point defines the price at which transactions are priced, and is based on the path of the physical transfer of energy. While a market participant designates a market path based from a generation control area (GCA) to load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the LGEE/PJM Interface based on the market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the LGEE/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with a GCA of LGEE, at the SouthIMP interface pricing point.

Interfaces differ from interface pricing points. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[31] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. According to the PJM Interface Price Definition Methodology, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[32] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[33] Table 8-14 presents the interface pricing points used in 2011.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. Real-Time Energy Market transaction prices are determined based on transaction details as defined below:

- Real-Time Energy Market Imports: For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. The

30 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

31 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

32 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> . (Accessed March 1, 2012)

33 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	675.9	414.1	468.0	243.5	429.8	335.0	500.6	364.0	230.5	352.1	436.4	413.9	4,863.8
LINDENVFT	(156.0)	(145.3)	(115.1)	(128.9)	(90.5)	(77.8)	(25.1)	(90.8)	(121.9)	(40.9)	(29.3)	(39.7)	(1,061.4)
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	(1,491.8)	(1,449.0)	(1,825.9)	(1,916.3)	(1,575.4)	(1,611.9)	(2,154.5)	(1,934.1)	(2,334.5)	(1,740.6)	(2,324.6)	(2,952.2)	(23,310.8)
NEPTUNE	(404.2)	(370.6)	(375.6)	(284.6)	(379.5)	(235.7)	(365.0)	(450.8)	(307.0)	(381.7)	(325.4)	(436.6)	(4,316.8)
NORTHWEST	(5.3)	(6.9)	(8.6)	(7.5)	(1.1)	(1.4)	(2.6)	(0.7)	(19.0)	(4.5)	(5.1)	(3.4)	(66.2)
NYIS	(773.9)	(724.2)	(525.8)	(440.0)	(253.4)	(352.2)	(539.3)	(799.3)	(710.5)	(609.6)	(504.7)	(488.5)	(6,721.2)
OVEC	1,242.2	1,110.7	1,065.8	1,018.9	1,030.7	1,014.6	1,040.8	1,011.9	828.9	666.5	759.6	903.9	11,694.6
SOUTHIMP/EXP	1,167.4	1,009.2	585.1	422.8	316.9	424.7	1,032.5	275.1	578.1	901.7	1,130.3	1,312.2	9,156.0
CPLEEXP	(106.2)	(31.0)	(44.0)	(31.9)	(57.0)	(91.6)	(86.1)	(83.5)	(52.5)	(14.3)	(14.3)	(35.2)	(647.5)
CPLEIMP	0.2	0.9	0.3	1.7	5.0	8.2	3.6	1.2	1.1	6.2	0.6	1.4	30.4
DUKEXP	(189.8)	(60.0)	(153.2)	(133.8)	(151.7)	(132.5)	(245.9)	(348.5)	(181.7)	(218.9)	(315.3)	(208.2)	(2,339.5)
DUKIMP	87.0	146.9	70.1	93.8	89.6	89.2	151.5	82.3	61.6	65.5	71.6	66.8	1,076.1
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	68.6	100.4	46.7	67.0	24.9	18.3	12.3	5.1	21.2	68.2	76.6	82.2	591.6
SOUTHEXP	(245.8)	(119.6)	(128.7)	(203.1)	(257.7)	(209.9)	(144.6)	(191.8)	(78.8)	(134.8)	(53.3)	(69.4)	(1,837.6)
SOUTHIMP	1,574.7	989.0	821.0	650.8	683.5	785.6	1,358.3	852.7	833.5	1,145.0	1,368.5	1,476.9	12,539.5
SOUTHWEST	(21.4)	(17.4)	(27.1)	(21.8)	(19.8)	(42.6)	(16.8)	(42.4)	(26.2)	(15.2)	(4.1)	(2.3)	(257.0)
Total	254.3	(162.0)	(732.1)	(1,092.1)	(522.5)	(504.7)	(512.8)	(1,624.6)	(1,855.3)	(856.9)	(862.8)	(1,290.3)	(9,761.8)

sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- Real-Time Energy Market Exports: For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the SouthEXP Interface pricing point, the sink would then default to that new interface pricing point. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.
- Real-Time Energy Market Wheels: For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface pricing point as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag shows that the physical flow would enter PJM at an interface other than the SouthIMP Interface pricing point, the source would then default to that new interface pricing point. Similarly, if the LCA on the NERC Tag shows that the physical flow would leave PJM at an interface other than the NYIS Interface pricing point, the sink would then default to that new interface pricing point.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[34] Table 8-4 through Table 8-6 show the Real-Time Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Real-Time Market is shown by interface pricing point for 2011 in Table 8-4, while gross imports and exports are shown in Table 8-5 and Table 8-6.

In the Real-Time Energy Market, in 2011 there were net exports at nine of PJM's 17 interface pricing points

34 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	695.7	442.3	472.9	246.6	429.8	336.6	503.4	365.4	233.1	352.5	436.5	413.9	4,928.7
LINDENVFT	0.0	0.0	0.0	0.0	0.0	14.3	51.7	27.9	10.6	19.1	17.6	24.4	165.6
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	195.2	184.1	108.8	66.1	107.6	45.9	76.5	69.2	43.8	58.7	44.0	32.4	1,032.3
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.1	0.7	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4
NYIS	676.3	534.7	646.6	686.3	909.1	960.0	1,089.7	927.5	720.1	631.8	619.2	688.8	9,090.1
OVEC	1,242.2	1,110.7	1,091.3	1,019.0	1,030.7	1,014.6	1,063.6	1,013.7	834.7	666.6	782.2	929.2	11,798.5
SOUTHIMP/EXP	1,730.6	1,237.2	938.1	813.4	803.1	901.3	1,525.7	941.3	917.3	1,284.8	1,517.3	1,627.3	14,237.5
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.2	0.9	0.3	1.7	5.0	8.2	3.6	1.2	1.1	6.2	0.6	1.4	30.4
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	87.0	146.9	70.1	93.8	89.6	89.2	151.5	82.3	61.6	65.5	71.6	66.8	1,076.1
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	68.6	100.4	46.7	67.0	24.9	18.3	12.3	5.1	21.2	68.2	76.6	82.2	591.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,574.7	989.0	821.0	650.8	683.5	785.6	1,358.3	852.7	833.5	1,145.0	1,368.5	1,476.9	12,539.5
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,540.1	3,509.7	3,257.7	2,831.4	3,280.8	3,272.7	4,310.7	3,344.9	2,759.5	3,013.6	3,416.9	3,716.0	41,254.1

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	19.8	28.1	4.9	3.1	0.0	1.6	2.8	1.3	2.6	0.5	0.1	0.0	64.8
LINDENVFT	156.0	145.3	115.1	128.9	90.5	92.1	76.8	118.7	132.5	59.9	46.9	64.1	1,226.9
MICHFE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	1,686.9	1,633.1	1,934.7	1,982.4	1,683.0	1,657.8	2,231.0	2,003.3	2,378.3	1,799.3	2,368.6	2,984.6	24,343.1
NEPTUNE	404.2	370.6	375.6	284.6	379.5	235.7	365.0	450.8	307.0	381.7	325.4	436.6	4,316.8
NORTHWEST	5.5	7.6	8.6	7.6	1.6	1.4	2.6	0.8	19.0	4.5	5.1	3.4	67.5
NYIS	1,450.2	1,258.9	1,172.3	1,126.3	1,162.5	1,312.2	1,629.0	1,726.8	1,430.5	1,241.4	1,123.9	1,177.2	15,811.3
OVEC	0.0	0.0	25.5	0.0	0.0	0.0	22.8	1.8	5.8	0.0	22.6	25.3	103.9
SOUTHIMP/EXP	563.2	228.0	353.0	390.6	486.2	476.7	493.3	666.2	339.2	383.1	387.0	315.1	5,081.5
CPLEEXP	106.2	31.0	44.0	31.9	57.0	91.6	86.1	83.5	52.5	14.3	14.3	35.2	647.5
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	189.8	60.0	153.2	133.8	151.7	132.5	245.9	348.5	181.7	218.9	315.3	208.2	2,339.5
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	245.8	119.6	128.7	203.1	257.7	209.9	144.6	191.8	78.8	134.8	53.3	69.4	1,837.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	21.4	17.4	27.1	21.8	19.8	42.6	16.8	42.4	26.2	15.2	4.1	2.3	257.0
Total	4,285.8	3,671.8	3,989.8	3,923.5	3,803.3	3,777.4	4,823.4	4,969.6	4,614.9	3,870.5	4,279.7	5,006.3	51,015.9

eligible for real-time transactions.[35] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 84.7 percent of the total net exports: PJM/MISO with 57.5 percent, PJM/NYIS with 16.6 percent and PJM/NEPTUNE (NEPT) with 10.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 29.8 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total net imports: PJM/SouthIMP with 40.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 38.0 percent of the net import volume.[36]

Day-Ahead Interface Imports and Exports

Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule

35 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

36 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (MICHFE and NCMPAEXP).

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(11.3)	89.8	126.8	234.4	159.9	(83.0)	(322.5)	(673.9)	(617.9)	(213.6)	13.6	6.3	(1,291.4)
CPLW	17.1	6.4	1.8	11.0	5.9	15.4	45.6	42.1	18.3	43.4	51.1	27.2	285.4
DUK	91.8	115.8	41.0	789.1	234.0	(240.7)	(617.8)	(495.5)	39.2	20.4	32.1	(25.5)	(16.2)
EKPC	(27.5)	(18.4)	27.8	6.8	(5.3)	1.0	(9.6)	(2.9)	(0.3)	(3.0)	(0.5)	(0.9)	(32.9)
LGEE	19.0	1.8	2.0	16.6	35.5	1.9	22.5	19.7	(2.1)	(2.0)	(21.7)	(12.3)	80.9
MEC	(458.7)	(421.3)	(463.2)	(455.3)	(472.2)	(437.3)	(542.1)	(493.2)	(512.4)	(525.7)	(512.6)	(502.3)	(5,796.3)
MISO	2,144.6	904.6	(182.2)	697.3	452.5	1,480.9	1,717.3	1,083.9	709.7	310.0	(199.3)	99.5	9,218.7
ALTE	1,996.5	908.2	99.1	833.9	1,037.2	1,333.0	911.8	729.9	583.2	(283.7)	(819.3)	(1,113.2)	6,216.7
ALTW	164.8	(49.7)	(48.1)	(40.1)	(7.3)	139.3	(0.4)	(42.6)	(205.5)	(74.1)	(198.4)	(183.1)	(545.2)
AMIL	34.6	70.2	67.5	31.0	33.6	(4.6)	74.1	(129.5)	(687.4)	(323.0)	41.1	32.0	(760.2)
CIN	(125.8)	(90.5)	(175.1)	(94.3)	(18.0)	(131.4)	(0.4)	100.0	178.4	217.7	114.7	315.4	290.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.7)	(0.0)	(1.4)	(0.1)	0.0	(3.1)
FE	(189.2)	(339.8)	(317.2)	(479.3)	(1,299.6)	(1.5)	0.0	0.0	0.0	0.0	0.0	0.0	(2,626.5)
IPL	(175.6)	(162.6)	(163.9)	(75.1)	(123.5)	(97.9)	(152.7)	(106.0)	(125.5)	(161.9)	(194.6)	(183.9)	(1,723.1)
MECS	742.4	580.2	567.2	591.2	992.6	336.2	931.9	816.5	1,150.4	898.1	732.5	769.7	9,108.9
NIPS	(280.6)	(111.0)	(130.3)	(65.8)	(108.9)	(90.9)	(50.9)	(1.7)	(6.8)	12.5	10.0	(39.8)	(864.1)
WEC	(22.6)	99.6	(81.4)	(4.3)	(53.7)	(1.4)	3.8	(281.1)	(177.1)	25.6	114.7	502.3	124.6
NYISO	(892.0)	(681.9)	(496.7)	(220.9)	611.3	(242.7)	(987.4)	(1,169.2)	(902.6)	(769.2)	(673.8)	(919.7)	(7,344.8)
LIND	(105.0)	(104.7)	(77.9)	(110.8)	(75.0)	(171.2)	(659.8)	(740.4)	(822.6)	(279.9)	(54.5)	(48.9)	(3,250.9)
NEPT	(427.9)	(379.7)	(385.0)	(298.1)	(405.2)	(250.0)	(396.6)	(508.6)	(339.6)	(395.2)	(362.6)	(450.5)	(4,598.9)
NYIS	(359.1)	(197.5)	(33.8)	187.9	1,091.5	178.5	69.0	79.8	259.6	(94.0)	(256.6)	(420.3)	505.0
OVEC	1,046.0	1,051.1	1,279.5	1,502.8	1,636.3	1,167.6	1,025.6	643.8	1,163.3	564.8	(390.9)	1,859.2	12,549.0
TVA	282.8	111.2	106.7	85.8	56.5	55.6	(422.1)	(489.9)	(118.6)	(116.8)	(237.5)	(390.1)	(1,076.4)
Total	2,211.7	1,159.2	443.4	2,667.6	2,714.6	1,718.7	(90.4)	(1,535.1)	(223.5)	(691.7)	(1,939.5)	141.3	6,576.2

could be supported in the Real-Time Energy Market.[37] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.

A fixed Day-Ahead Energy Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated import or export pricing point. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Energy Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Energy Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations. If the market participant does not provide a corresponding transaction in the Real-Time Energy Market, they are subject to the balancing market settlement.

Dispatchable transactions in the Day-Ahead Energy Market are similar to those in the Real-Time Energy Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Energy Market represent a financial obligation. If the market

37 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	137.6	146.3	197.4	305.0	242.6	29.5	40.6	45.3	48.2	33.0	28.5	34.6	1,288.6
CPLW	19.5	6.5	8.1	13.9	24.6	27.2	64.9	69.3	47.9	71.8	87.9	48.2	489.8
DUK	150.8	155.5	88.5	935.0	269.0	50.9	99.2	50.2	55.3	44.9	46.4	48.5	1,994.2
EKPC	5.4	0.0	28.3	6.8	6.3	2.8	0.2	0.3	0.3	1.1	0.5	0.3	52.5
LGEE	21.6	2.1	13.5	17.1	40.8	41.6	71.0	21.6	14.1	15.9	2.7	12.0	274.0
MEC	21.7	19.8	20.1	8.2	15.9	67.5	102.8	107.1	106.2	74.7	60.8	131.9	736.7
MISO	7,394.0	5,782.6	5,316.8	4,391.0	5,686.9	5,791.8	7,048.5	7,143.7	6,968.3	5,502.7	6,247.2	7,793.2	75,066.8
ALTE	4,872.3	3,576.6	3,109.0	2,156.0	2,959.3	3,808.9	3,588.3	3,520.1	3,761.2	2,596.8	2,470.0	2,916.7	39,335.2
ALTW	375.6	52.1	29.0	19.3	74.1	284.8	183.7	129.2	51.9	72.0	41.8	53.3	1,366.7
AMIL	44.8	71.1	70.7	34.2	35.8	45.2	77.2	34.2	50.9	23.1	43.7	32.3	563.3
CIN	266.2	440.5	360.6	511.2	263.4	728.0	760.3	692.0	662.2	583.9	926.4	970.3	7,165.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	232.9	140.5	141.0	55.5	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	586.8
IPL	17.0	2.9	0.0	6.5	2.8	1.7	0.8	1.0	4.8	0.0	1.5	1.5	40.4
MECS	1,409.4	1,207.9	1,438.1	1,402.0	2,167.9	772.1	2,254.1	2,644.6	2,260.5	1,890.5	2,214.2	2,785.6	22,446.9
NIPS	32.0	48.2	27.0	33.9	11.6	29.2	33.2	35.2	26.0	43.0	58.5	17.0	394.8
WEC	143.7	242.8	141.4	172.4	155.0	121.9	151.0	87.5	150.8	293.5	491.2	1,016.5	3,167.7
NYISO	910.1	988.6	1,149.1	1,399.2	2,467.1	1,560.2	1,666.6	1,763.1	1,997.7	1,520.7	1,305.1	1,266.5	17,994.0
LIND	0.0	0.0	0.0	0.0	0.0	8.7	29.1	22.2	0.8	1.6	2.7	3.2	68.3
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	1,399.2	2,467.1	1,551.5	1,637.5	1,740.9	1,997.0	1,519.1	1,302.4	1,263.3	17,925.7
OVEC	1,272.8	1,355.2	1,898.8	1,976.7	2,223.0	1,886.6	2,006.4	2,750.1	2,146.5	2,091.7	2,412.5	3,918.9	25,939.4
TVA	412.1	318.7	318.9	341.8	286.8	529.3	748.6	639.7	421.3	470.5	409.8	285.0	5,182.5
Total	10,345.6	8,775.5	9,039.6	9,394.6	11,263.0	9,987.4	11,848.8	12,590.5	11,805.9	9,827.0	10,601.5	13,539.2	129,018.5

participant does not meet the commitment in the Real-Time Energy Market, they are subject to the balancing market settlement.

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants.

- Day-Ahead Energy Market Imports: For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- Day-Ahead Energy Market Exports: For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.
- Day-Ahead Energy Market Wheels: For day-ahead wheel through energy transactions, the market participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

Because market participants choose the interface pricing point(s) they wish to have associated with their transaction in the Day-Ahead Energy Market, the scheduled interface is less meaningful than in the Real-Time Energy Market. In Table 8-7, Table 8-8 and Table 8-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not necessarily match that of the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction. In the interface tables below, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow. Table 8-7 through Table 8-9 show the Day-Ahead interchange

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): Calendar year 2011

Interface	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	148.9	56.5	70.7	70.5	82.7	112.5	363.1	719.2	666.1	246.5	14.9	28.4	2,579.9
CPLW	2.4	0.1	6.2	2.9	18.6	11.8	19.2	27.2	29.6	28.4	36.8	21.1	204.4
DUK	59.1	39.7	47.5	145.9	35.0	291.6	717.0	545.7	16.2	24.5	14.3	74.0	2,010.4
EKPC	32.9	18.4	0.5	0.0	11.6	1.9	9.9	3.2	0.6	4.1	1.1	1.2	85.4
LGEE	2.6	0.3	11.5	0.5	5.2	39.8	48.5	1.9	16.2	17.9	24.5	24.3	193.1
MEC	480.4	441.2	483.3	463.4	488.1	504.8	644.8	600.3	618.6	600.4	573.5	634.2	6,533.0
MISO	5,249.4	4,878.0	5,499.0	3,693.8	5,234.4	4,310.8	5,331.2	6,059.8	6,258.6	5,192.7	6,446.5	7,693.8	65,848.1
ALTE	2,875.8	2,668.4	3,009.9	1,322.1	1,922.0	2,475.9	2,676.5	2,790.1	3,178.1	2,880.5	3,289.3	4,029.9	33,118.5
ALTW	210.8	101.8	77.1	59.4	81.4	145.5	184.1	171.8	257.4	146.0	240.3	236.4	1,911.9
AMIL	10.2	0.9	3.2	3.2	2.2	49.8	3.1	163.7	738.3	346.1	2.6	0.3	1,323.5
CIN	392.0	531.0	535.7	605.5	281.5	859.4	760.6	592.0	483.8	366.2	811.7	654.8	6,874.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	1.4	0.1	0.0	3.1
FE	422.1	480.2	458.2	534.8	1,316.6	1.5	0.0	0.0	0.0	0.0	0.0	0.0	3,213.4
IPL	192.6	165.5	163.9	81.6	126.3	99.6	153.5	106.9	130.2	161.9	196.0	185.5	1,763.6
MECS	667.0	627.7	870.9	810.8	1,175.4	435.9	1,322.1	1,828.1	1,110.1	992.4	1,481.7	2,015.9	13,338.0
NIPS	312.6	159.2	157.3	99.8	120.4	120.0	84.1	36.9	32.8	30.5	48.5	56.8	1,258.9
WEC	166.3	143.3	222.8	176.6	208.7	123.2	147.1	368.6	327.9	267.8	376.5	514.2	3,043.1
NYISO	1,802.1	1,670.5	1,645.8	1,620.1	1,855.7	1,802.9	2,654.0	2,932.4	2,900.3	2,289.9	1,978.9	2,186.2	25,338.7
LIND	105.0	104.7	77.9	110.8	75.0	179.9	688.9	762.7	823.4	281.5	57.3	52.1	3,319.1
NEPT	427.9	379.7	385.0	298.1	405.2	250.0	396.6	508.6	339.6	395.2	362.6	450.5	4,598.9
NYIS	1,269.2	1,186.1	1,182.9	1,211.2	1,375.6	1,373.0	1,568.5	1,661.1	1,737.4	1,613.1	1,559.0	1,683.6	17,420.7
OVEC	226.8	304.1	619.3	474.0	586.7	719.0	980.8	2,106.3	983.2	1,527.0	2,803.4	2,059.7	13,390.4
TVA	129.3	207.5	212.2	255.9	230.3	473.7	1,170.7	1,129.5	539.9	587.3	647.3	675.1	6,258.9
Total	8,133.9	7,616.3	8,596.2	6,727.0	8,548.4	8,268.7	11,939.2	14,125.6	12,029.3	10,518.7	12,541.1	13,397.9	122,442.3

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	332.0	186.1	101.1	185.4	219.5	457.7	372.8	147.6	97.0	250.2	(83.7)	(256.2)	2,009.5
LINDENVFT	(142.5)	(153.1)	(129.7)	(163.6)	(162.2)	(130.5)	(111.7)	(94.9)	(105.1)	(101.6)	12.4	69.8	(1,212.6)
MICHFE	(63.5)	(343.7)	(215.0)	(149.8)	(144.6)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(916.5)
MISO	(98.4)	(233.8)	(442.7)	(276.2)	202.2	174.1	176.9	(48.5)	(18.1)	282.3	218.5	586.3	522.5
NEPTUNE	(594.7)	(652.6)	(529.4)	(414.2)	(584.0)	(388.4)	(536.4)	(671.0)	(547.4)	(621.7)	(500.6)	(786.4)	(6,826.8)
NIPSCO	615.2	355.3	(30.6)	(355.3)	(90.3)	37.1	206.7	(59.2)	116.4	271.0	234.1	139.3	1,439.6
NORTHWEST	994.2	875.2	564.8	398.9	115.1	(94.3)	(118.1)	(152.2)	(89.6)	(623.5)	(699.1)	(616.5)	554.9
NYIS	137.2	281.9	263.9	404.8	839.2	580.8	638.4	525.1	563.6	231.2	53.2	(26.5)	4,492.7
OVEC	1,161.4	982.1	557.9	1,518.0	1,658.4	1,266.5	1,321.5	924.2	1,139.9	433.4	(711.3)	1,606.4	11,858.5
SOUTHIMP/EXP	(129.3)	(138.3)	303.3	1,519.5	661.4	(184.2)	(2,040.7)	(2,106.2)	(1,380.2)	(813.1)	(462.9)	(574.8)	(5,345.6)
CPLEEXP	(297.4)	(100.6)	(109.9)	(103.7)	(104.4)	(91.5)	(89.8)	(80.7)	(47.4)	(14.3)	(10.6)	(27.5)	(1,077.9)
CPLEIMP	304.8	269.2	274.7	351.5	935.0	1.9	0.4	1.2	0.0	0.0	0.0	0.0	2,138.7
DUKEXP	(57.9)	(40.1)	(50.8)	(209.0)	(330.5)	(8.4)	(4.5)	(10.4)	0.0	0.0	0.0	0.0	(711.5)
DUKIMP	98.4	107.1	37.9	1,211.0	315.4	4.5	45.9	1.0	8.7	1.2	1.9	5.2	1,838.3
NCMPAEXP	(154.6)	(341.4)	(61.4)	(78.3)	(452.6)	(0.5)	(0.4)	(0.4)	(0.4)	(0.2)	(0.4)	(0.9)	(1,091.5)
NCMPAIMP	38.0	26.8	44.9	111.6	73.1	0.0	0.0	0.0	2.4	0.0	0.0	0.0	296.9
SOUTHEAST	36.7	87.9	133.1	42.8	140.5	(344.8)	(1,179.7)	(1,075.2)	(1,077.0)	(464.2)	153.3	(4.8)	(3,551.2)
SOUTHEXP	(353.1)	(355.7)	(302.8)	(295.7)	(373.7)	(736.4)	(1,557.7)	(1,455.0)	(831.1)	(1,181.4)	(1,302.3)	(1,401.4)	(10,146.2)
SOUTHIMP	616.1	265.9	300.7	270.4	386.5	686.6	804.4	622.3	481.2	410.2	411.7	457.5	5,713.4
SOUTHWEST	(360.6)	(57.4)	36.9	219.0	71.9	304.3	(59.3)	(108.9)	83.4	435.7	283.4	397.0	1,245.5
Total	2,211.7	1,159.2	443.4	2,667.6	2,714.6	1,718.7	(90.4)	(1,535.1)	(223.5)	(691.7)	(1,939.5)	141.3	6,576.2

totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for 2011 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

There were net imports in the Day-Ahead Energy Market at seven of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.7 percent, PJM/Neptune (NEPT) with 20.4 percent and PJM/Linden (LIND) with 14.4 percent. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 32.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95.5 percent of the total net imports: PJM/OVEC with 43.0 percent, PJM/Michigan

Table 8-11 Day-Ahead scheduled gross import volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	562.9	437.2	345.3	418.0	537.1	890.1	1,033.3	855.8	680.3	600.7	637.8	677.8	7,676.2
LINDENVFT	0.0	0.0	0.0	0.0	0.0	7.4	100.6	312.8	293.9	211.0	292.9	428.5	1,647.1
MICHFE	662.3	309.2	343.8	301.7	598.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,215.5
MISO	1,603.0	1,208.7	1,202.6	861.6	1,128.4	1,436.4	1,487.4	1,220.0	1,574.5	2,098.1	2,339.1	3,048.1	19,207.8
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPSCO	995.0	908.4	773.5	339.9	634.1	319.7	685.5	536.6	392.0	395.5	542.5	509.7	7,032.5
NORTHWEST	1,625.0	1,407.6	1,185.2	907.6	808.1	710.3	646.0	536.2	515.7	431.7	403.5	666.0	9,842.8
NYIS	1,430.9	1,386.0	1,475.4	1,676.5	2,273.3	2,107.1	2,377.5	2,272.0	2,230.8	1,622.1	1,454.7	1,605.5	21,911.6
OVEC	1,887.3	1,856.3	2,275.7	2,392.4	2,679.9	2,650.2	3,271.4	3,624.0	2,660.4	2,579.1	3,058.1	4,821.6	33,756.3
SOUTHIMP/EXP	1,579.3	1,262.0	1,438.2	2,497.0	2,603.7	1,866.1	2,247.0	3,233.1	3,458.5	1,888.8	1,873.0	1,782.0	25,728.8
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	304.8	269.2	274.7	351.5	935.0	1.9	0.4	1.2	0.0	0.0	0.0	0.0	2,138.7
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	98.4	107.1	37.9	1,211.0	315.4	4.5	45.9	1.0	8.7	1.2	1.9	5.2	1,838.3
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	38.0	26.8	44.9	111.6	73.1	0.0	0.0	0.0	2.4	0.0	0.0	0.0	296.9
SOUTHEAST	173.8	192.3	268.1	107.2	347.0	417.6	603.9	977.4	791.2	510.2	612.9	461.8	5,463.4
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.4
SOUTHIMP	616.1	265.9	300.7	270.4	386.5	686.6	804.4	622.3	481.2	410.2	411.7	457.5	5,713.4
SOUTHWEST	348.0	400.8	511.8	445.4	546.6	755.5	792.5	1,631.2	2,175.0	967.3	846.1	857.5	10,277.6
Total	10,345.6	8,775.5	9,039.6	9,394.6	11,263.0	9,987.4	11,848.8	12,590.5	11,805.9	9,827.0	10,601.5	13,539.2	129,018.5

Table 8-12 Day-Ahead scheduled gross export volume by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	230.9	251.2	244.1	232.5	317.6	432.4	660.4	708.2	583.3	350.5	721.5	934.0	5,666.7
LINDENVFT	142.5	153.1	129.7	163.6	162.2	137.9	212.3	407.7	399.0	312.6	280.5	358.8	2,859.7
MICHFE	725.7	652.9	558.8	451.4	743.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,132.0
MISO	1,701.4	1,442.5	1,645.4	1,137.8	926.2	1,262.4	1,310.5	1,268.5	1,592.5	1,815.8	2,120.5	2,461.7	18,685.2
NEPTUNE	594.7	652.6	529.4	414.2	584.0	388.4	536.4	671.0	547.4	621.7	500.6	786.4	6,826.8
NIPSCO	379.8	553.1	804.2	695.2	724.3	282.7	478.8	595.8	275.6	124.5	308.4	370.5	5,592.9
NORTHWEST	630.8	532.4	620.4	508.7	693.0	804.7	764.0	688.4	605.2	1,055.2	1,102.6	1,282.5	9,287.9
NYIS	1,293.7	1,104.1	1,211.5	1,271.7	1,434.1	1,526.3	1,739.0	1,746.9	1,667.2	1,390.9	1,401.5	1,632.0	17,419.0
OVEC	725.8	874.2	1,717.8	874.4	1,021.5	1,383.6	1,949.8	2,699.8	1,520.4	2,145.7	3,769.4	3,215.2	21,897.8
SOUTHIMP/EXP	1,708.6	1,400.3	1,134.9	977.5	1,942.3	2,050.3	4,287.8	5,339.3	4,838.7	2,701.9	2,336.0	2,356.8	31,074.4
CPLEEXP	297.4	100.6	109.9	103.7	104.4	91.5	89.8	80.7	47.4	14.3	10.6	27.5	1,077.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	57.9	40.1	50.8	209.0	330.5	8.4	4.5	10.4	0.0	0.0	0.0	0.0	711.5
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	154.6	341.4	61.4	78.3	452.6	0.5	0.4	0.4	0.4	0.2	0.4	0.9	1,091.5
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	137.1	104.4	135.0	64.3	206.5	762.5	1,783.6	2,052.6	1,868.2	974.4	459.6	466.6	9,014.6
SOUTHEXP	353.1	355.7	302.8	295.7	373.7	736.4	1,557.7	1,455.0	831.1	1,181.4	1,302.7	1,401.4	10,146.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	708.6	458.1	474.9	226.4	474.6	451.2	851.9	1,740.1	2,091.6	531.5	562.7	460.5	9,032.2
Total	8,133.9	7,616.3	8,596.2	6,727.0	8,548.4	8,268.7	11,939.2	14,125.6	12,029.3	10,518.7	12,541.1	13,397.9	122,442.3

Electric Coordinated System (MECS) with 31.2 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 21.3 percent.

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-12 show the Day-Ahead Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Day-Ahead Market is shown by interface pricing point for 2011 in Table 8-10, while gross imports and exports are shown in Table 8-11 and Table 8-12.

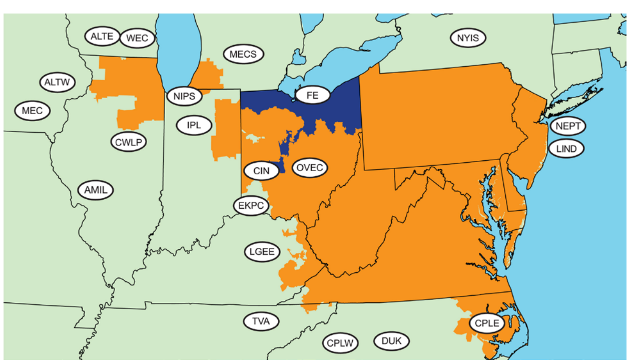
In the Day-Ahead Energy Market, in 2011 there were net exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 80.3 percent of the total net exports: PJM/SouthEXP with 39.7 percent, PJM/

Table 8-13 Active interfaces: Calendar year 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active						
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

NEPTUNE (NEPT) with 26.7 percent, and PJM/Southeast with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 13.9 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 26.7 percent and PJM/LINDEN with 4.7 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eleven PJM interface pricing points had net imports, with three importing interface pricing points accounting for 68.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.9 percent, PJM/SouthIMP with 17.8 percent and PJM/NYIS with 14.0 percent of the net import volume.

Figure 8-3 PJM's footprint and its external interfaces



Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules, OASIS designation curtailments (willing to pay congestion or not willing to pay congestion), and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell energy into PJM). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase energy from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or

Table 8-14 Active pricing points: 2011

	PJM 2011 Pricing Points											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MICHFE	Active	Active	Active	Active	Active	Active						
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If the system operator does not feel that the transaction will be economic, they will elect to not load the transaction, or to curtail the dispatchable transaction at the top of the next hour if it has already been loaded. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. For importing dispatchable transactions, if the resulting hourly integrated prices are such that the transaction should not have been loaded, the transaction will be made whole through operating reserve credits.

Not willing to pay congestion transactions should be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Interactions with Bordering Areas

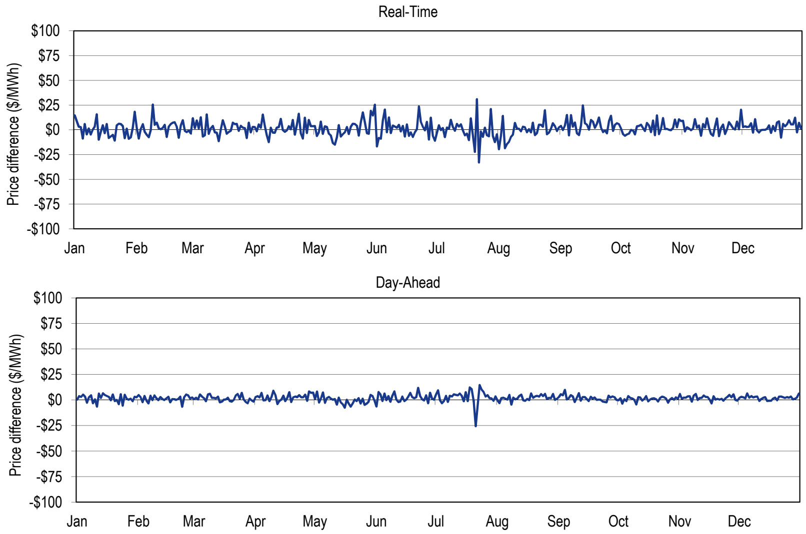
PJM Interface Pricing with Organized Markets

In 2011, the direction of power flows at the borders between PJM and MISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a significant number of hours, 55 percent between PJM and MISO and 48 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag. PJM is engaged in preliminary discussions with both MISO and NYISO on interface pricing.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): Calendar year 2011



entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[38] within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[39]

Real-Time Prices

In 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $32.32 while the MISO LMP at the border was $34.01, a difference of $1.69. While the average hourly LMP difference at the PJM/MISO border was only $1.69, the average of the absolute values of the hourly differences was $11.48. The average hourly flow during the calendar year 2011 was -1,570 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 45 percent of hours in 2011. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $15.02. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $8.74. In 2011, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $14.27. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $21.16. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $19.89. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $7.40. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $62.8 million at the PJM/MISO Interface.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

In 2011, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $20.94 for the PJM/MISO Interface price and $24.33 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $23.40. The average of the absolute value of the hourly price difference was $11.53. Absolute values

38 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

39 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010).

reflect price differences regardless of whether they are positive or negative.

The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, although with a lag that permits substantial price differences in both directions.

Day-Ahead Prices

The 2011 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $33.00 and $34.80. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface was $1.80 in 2011. In the Day-Ahead Energy Market, gross exports to MISO were 65,848.1 GWh in 2011.

In 2011, the difference between the day-ahead PJM/MISO Interface price and the day-ahead MISO/PJM Interface price fluctuated between positive and negative about four times per day. The standard deviation of the hourly price was $14.52 for the PJM/MISO price and $13.10 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $6.74. The average of the absolute value of the hourly price difference was $4.26.

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected interchange for the next hour.

PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[40] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

Real-Time Prices

In 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and

40 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

the NYISO. In 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the PJM/NYISO border was $43.88 while the NYISO LMP at the border was $42.33, a difference of $1.55. While the average hourly LMP difference at the PJM/NYISO border was only $1.55, the average of the absolute value of the hourly difference was $13.31. The average hourly flow during the calendar year 2011 was -626 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 52 percent of the hours in 2011. In 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $12.01. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $14.56. In 2011, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $10.61. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $27.71. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $28.26. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $12.28. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $37.7 million at the PJM/NYIS Interface.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price fluctuated between positive and negative about seven times per day in 2011. The standard deviation of hourly price was $31.77 in 2011 for the PJM/NYIS Interface price and $31.69 in 2011 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $31.53 in 2011. The average of the absolute value of the hourly price difference was $13.30 in 2011. Absolute values reflect price differences without regard to whether they are positive or negative.

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2011

Day-Ahead Prices

The 2011 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $44.87 and $44.57. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price was $0.30 in 2011. In the Day-Ahead Energy Market, the gross exports to the NYISO were 17,420.7 GWh in 2011.

The difference between the day-ahead PJM/NYIS Interface price and the day-ahead NYISO/PJM proxy bus price fluctuated between positive and negative about four times per day in 2011. The

Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: Calendar year 2011

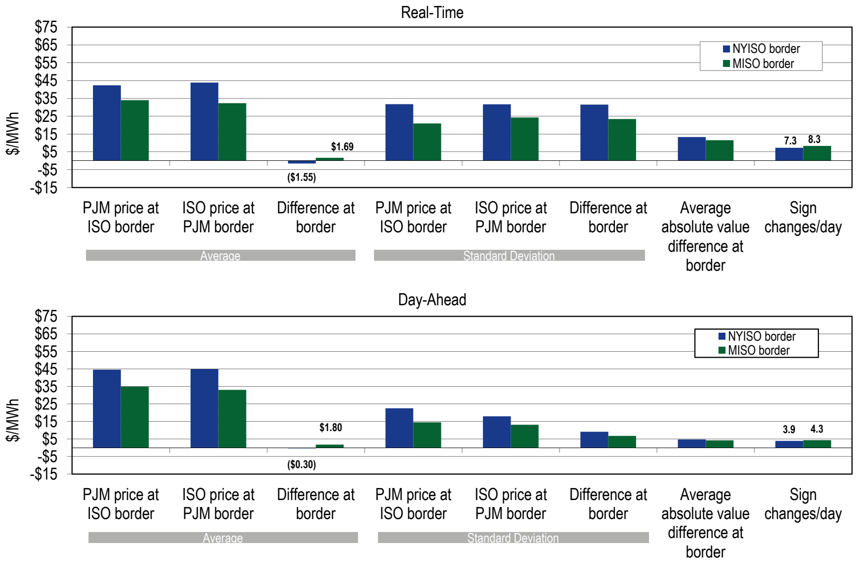
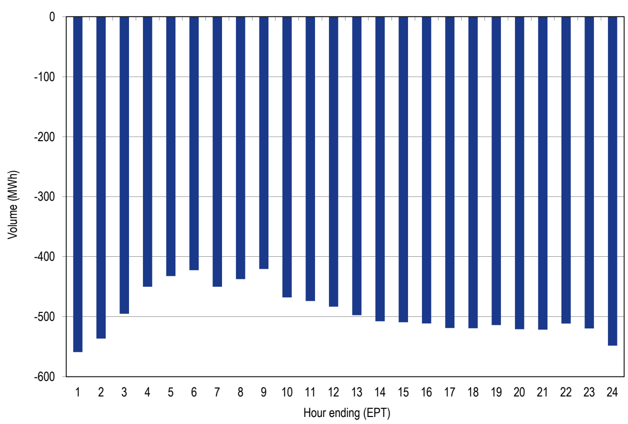


Figure 8-7 Neptune hourly average flow: Calendar year 2011



standard deviation of hourly price was $22.54 in 2011 for the PJM/NYIS Interface price and $17.96 in 2011 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $9.14 in 2011. The average of the absolute value of the hourly price difference was $4.75 in 2011. Absolute values reflect price differences without regard to whether they are positive or negative.

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 8-6, including average prices and measures of variability.

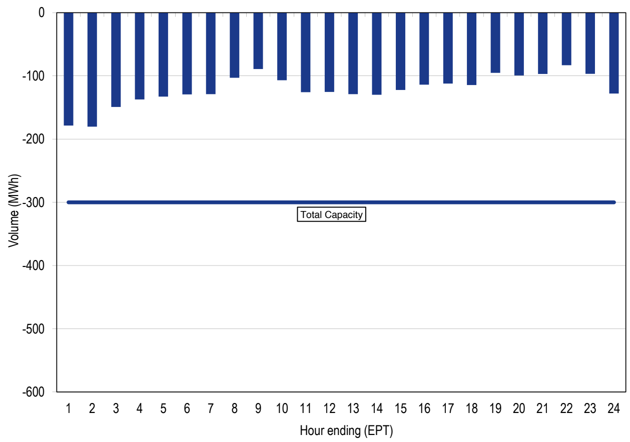
Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Neptune Interface was $48.20 while the NYISO LMP at the Neptune Bus was $54.11, a difference of $5.91. While the average hourly LMP difference at the PJM/Neptune border was $5.91, the average of the absolute value of the hourly difference was $20.38. The average hourly flow during the calendar year 2011 was -493 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours in 2011. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average pirce difference was $19.55. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $20.50. In 2011, for the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $32.8 million at the PJM/NEPT Interface.

Linden Variable Frequency Transformer (VFT) facility

On November 1, 2009, the Linden VFT facility was placed in service, providing an additional connection between PJM and the NYISO. The Linden VFT facility is

Figure 8-8 Linden hourly average flow: Calendar year 2011



a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[41] On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. In 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Linden Interface was $47.19 while the NYISO LMP at the Linden Bus was $48.70, a difference of $1.51. While the average hourly LMP difference at the PJM/Linden border was $1.51, the average of the absolute value of the hourly difference was $16.24. The average hourly flow during the calendar year 2011 was -121 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 61 percent of the hours in 2011. Following June 1, 2011, when bidirectional flows were permitted across the Linden VFT Facility, a total of 1,064 hours, out of the 5,136 hours, were imports into PJM. Of those 1,064 hours, 580 hours were economic (i.e. the NYISO/PJM Interface price was lower than the PJM/NYISO Interface price). When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM (580 hours), the average price difference was $24.33. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when power flows were from NYISO to PJM (484 hours), the average price difference was $17.14. In 2011, for the hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was $7.4 million at the PJM/LIND Interface.

Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection will be a submarine AC cable system. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). The Hudson DC line is expected to be in service in late 2012.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with MISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

41 See PJM Interconnection, L.L.C,Docket No. ER11-3250-000 (March 31, 2011).

PJM and MISO Joint Operating Agreement

The market to market coordination between PJM and MISO continued in 2011. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.

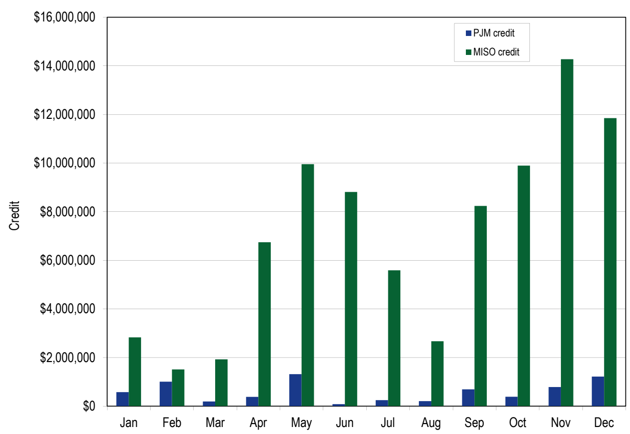
Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater then 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

CFs and RCFs can be added at any time throughout the year. As of December 31, 2008, there were 247 CFs and 256 RCFs. As of December 31, 2011, there were 335 CFs and 418 RCFs.

In 2011, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

Figure 8-9 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by MISO to PJM and a MISO credit is a payment by PJM to MISO. The largest payments from PJM to MISO in 2011 were the result of redispatch by MISO to relieve congestion on the Oak Grove – Galesburg for the loss of Nelson – Electric Junction line. Total PJM payments to MISO in 2011 were approximately $84.3 million, a 52 percent increase from the 2010 level. The largest payments from MISO to PJM in 2011 were the result of redispatch by PJM to relieve congestion on the Nelson – Electric Junction for the loss of Cherry Valley – Silver Lake line. Total MISO payments to PJM were approximately $7.1 million, a 64 percent decrease from the 2010 level.

Figure 8-9 Credits for coordinated congestion management: Calendar year 2011



In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report is expected to be completed and distributed early in the first quarter of 2012.

Generation in one RTO may affect congestion in the other RTO. To ensure that the most economic mix of generation is being utilized to control constraints, it is important to ensure that generators within each RTO are following the dispatch signal. If a generator remains on when the economic signal suggests it should be reduced, or come offline, the output from that generator could contribute to congestion, and may create the need to enter into market to market activity. When this is the case, the generator that is operating uneconomically may create congestion credits to be paid from one RTO to the other. The MMU suggests that the RTOs evaluate whether this is occurring and the appropriate impact on the congestion payments under the JOA.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued in 2011.[42] On December 30, 2010, the Commission issued an Order on Rehearing and Compliance which directed the NYISO to make interface pricing revisions by the second quarter of 2011 required that congestion management/market-to-market coordination for the Commission-jurisdictional RTO/ISOs be completed concurrently by the second quarter of 2011.[43]

In 2008, loop flows were created when NYISO pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[44] PJM's interface pricing calculations correctly reflected the actual power flows, but the NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

On December 22, 2011, the NYISO filed a compliance notice to confirm a timely development of new interface pricing software.[45] The MMU responded to the NYISO's filing on January 12, 2012.[46] In its response, the MMU contended that the interface pricing methodology proposed by the NYISO does not comply with the FERC's December 30, 2010 Order.[47]

On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that include a market to market process.[48] The filing included provisions for the congestion management protocol between PJM and the NYISO. Some key aspects of the process, such as the determination of the Firm Flow Entitlements and the incorporation of existing agreements on PAR operations within the market to market construct are still under discussion, and are expected to be completed by the end of the second quarter of 2012.

PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a

42 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

43 See 133 FERC ¶ 61,276 (2010).

44 See the *2008 State of the Market Report* for PJM, Volume II, "Interchange Transactions."

45 See "New York Independent System Operator, Inc.'s Compliance Notice." Docket No. ER08-1281-007 (December 22, 2011).

46 See "Protest of the Independent Market Monitor for PJM." Docket No. ER08-1281-005, -006, -007 and 010 (January 12, 2012).

47 The NYISO interface pricing methodology utilizes two scheduling modes. The "Conforming" scheduling mode assumes that scheduled and actual flows are aligned, and allows the NYISO to continue to price interchange based on scheduled rather than actual flows. The "Non-Conforming" mode assumes that scheduled and actual flows are not aligned, and the NYISO will price interchange schedules based on actual flows associated with a proxy bus The determination of scheduling modes is made quarterly. The MMU does not agree with this methodology, because it would permit pricing based on scheduled rather than actual flows and because it does not address interface pricing for GCAs which are not contiguous balancing authorities. The proposed solution would not address the Lake Erie loop flow issue.

48 See "Jointly Submitted Market-to Market Coordination Compliance Filing." Docket No. ER12-718-000 (December 30,2011).

yearly basis, and, in 2011, there were no developments. The agreement continued to be in effect in 2011.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[49] The MMU responded to the filing on February 23, 2010.[50] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010.[51] On May 28, 2010, the Commission conditionally approved the revised PJM/PEC JOA.[52] PJM and PEC were required to make a compliance filing within thirty days of the date of the order answering specific questions related to the impact of the scheduling arrangement on NERC standards and discriminatory access, the market pricing mechanisms with regards to eliminating the nuclear and hydro units from the calculation and the discriminatory use of export make whole payments under this agreement. On June 28, 2010, PJM and PEC filed their response.[53] The MMU responded to the compliance filing on July 19, 2010, reiterating the argument that the PJM/PEC JOA provides for preferential treatment to ATC and that the elimination of nuclear and hydro units from the interface price calculation is not consistent with the economics of locational marginal pricing.[54] The MMU moved for a technical conference to explore these issues.[55] On January 20, 2011, the Commission conditionally accepted the compliance filing made by PJM and Carolina Power, stating that the proposed CMP was a just and reasonable solution to managing congestion between Regional Transmission Organizations (RTOs) and other systems. The acceptance of the JOA revisions is subject to the condition that PJM file a revised provision to its tariff that details how similarly situated parties can elect to use such a scheduled arrangement, including the after-the-fact transmission reservations provisions.[56] The agreement remained in effect in 2011. On May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[57]

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement remained in effect in 2011.

Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using

49 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

50 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)

51 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.

52 See Docket No. ER10-713-000. Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Progress Energy Carolinas.

53 See "Compliance Filing," Docket No. ER10-713-002.

54 See "Comments and Motion for Technical Conference of the Independent Market Monitor for PJM," Docket No. ER10-713-002.

55 Id.

56 132 FERC ¶ 61,048 (2011).

57 Docket No. ER11-3637-000 (May 25, 2011)

Table 8-15 Con Edison and PSE&G wheeling settlement data: Calendar year 2011

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($2,173,141)	($2,471)	($2,175,611)	($12,580,355)	$0	($12,580,355)
Congestion Credit			$146,137			($12,803,800)
Adjustments			$15,611			$1,002,325
Net Charge			($2,337,360)			($778,879)

lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM.[58] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[59] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[60] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[61] PJM continued to operate under the terms of the protocol through 2011.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2011, PSE&G's revenues were more than its congestion charges by $778,879 after adjustments (revenues were less than its congestion charges by $1,028,909 in 2010.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2011, Con Edison's congestion credits were $2,319,278 more than its day-ahead congestion charges (Credits had been $3,066,001 less than charges in 2010 (Table 8-15)).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion

58 See "Section 3 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.

59 111 FERC ¶ 61,228 (2005).

60 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).

61 120 FERC ¶ 61,161 (2007)

credits, which were -$2,715,707 in 2011. The parties should address this issue.

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 1.2 percent of the hours in 2011.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[62] By order issued September 16, 2010, the Commission approved this settlement,[63] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[64]

Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

If PJM net actual interface flows were close to net scheduled interface flows, on average for 2011, it would not necessarily mean that there was no loop flow. Loop flows are measured at individual interfaces.There can be no difference between scheduled and actual flows for PJM and still be significant differences between scheduled and actual flows for specific individual interfaces. From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

In 2011, for PJM as a whole, net scheduled and actual interchange differed by 7.1 percent, an increase from

62 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

63 132 FERC ¶ 61,221 (2010).

64 See, e.g., Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

5.2 percent for the calendar year 2010.[65] In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[66]

Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 13,983 GWh exceeding scheduled imports of 2,929 GWh by 16,913 GWh or 577.4 percent, an average of 1,930 MW during each hour of the year. At the PJM/AMIL Interface, scheduled flows were imports of 10,215 GWh and actual flows were exports of 218 GWh, creating an imbalance of 10,433 GWh or 4,785.8 percent, an average of 1,191 MW during each hour of the year.

Every balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[67] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

Defined in this way, Table 8-17 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points. Following the consolidation of the Southeast and Southwest pricing points, a market participant requested grandfathered treatment to allow them to continue to receive the Southwest Interface Pricing Point. This pricing point is also a subset of the larger SouthIMP and SouthEXP Interface Pricing Points, and does not have physical ties that differ from the SouthIMP and SouthEXP Interafce Pricing Points.

Table 8-16 Net scheduled and actual PJM flows by interface (GWh): Calendar year 2011

Interface	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	6,960	(1,188)	8,147	(686.0%)
CPLW	(1,842)	2	(1,845)	(77,181.6%)
DUK	(2,371)	(271)	(2,100)	775.2%
EKPC	2,820	516	2,304	446.3%
LGEE	1,283	3,881	(2,598)	(66.9%)
MEC	(2,278)	(6,008)	3,730	(62.1%)
MISO	(13,752)	(4,627)	(9,125)	197.2%
ALTE	(6,038)	(3,425)	(2,612)	76.3%
ALTW	(2,471)	(875)	(1,596)	182.5%
AMIL	10,215	(218)	10,433	(4,786.5%)
CIN	(518)	1,074	(1,592)	(148.3%)
CWLP	(295)	-	(295)	0.0%
FE	(3,464)	(1,005)	(2,459)	244.6%
IPL	1,394	(284)	1,678	(590.1%)
MECS	(13,983)	2,929	(16,913)	(577.4%)
NIPS	(4,049)	(785)	(3,264)	415.8%
WEC	5,459	(2,037)	7,496	(367.9%)
NYISO	(11,150)	(12,321)	1,171	(9.5%)
LIND	(1,061)	(1,061)	-	0.0%
NEPT	(4,317)	(4,317)	-	0.0%
NYIS	(5,772)	(6,943)	1,171	(16.9%)
OVEC	7,667	11,695	(4,028)	(34.4%)
TVA	5,088	1,248	3,841	307.9%
Total	(7,576)	(7,072)	(504)	7.1%

The table is somewhat difficult to interpret, but provides some insight into the accuracy of the interface pricing points if the limitations are recognized.

Because the SouthIMP and SouthEXP Interface Pricing Points are virtually the same point, if there are actual net exports from the PJM footprint to the southern region, by default, there will not be actual flows on the SouthIMP Interface Pricing Point. Conversely, if there are actual net imports into the PJM footprint from the southern region, there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points that make up the southern region, comparing the net scheduled and net actual flows from the aggregate pricing points provides some insight on how effective the interface pricing point mappings are.

65 The "Net Scheduled" values shown in Table 8-16 include dynamic schedules. Dynamic schedules are flows from generating units that are physically located in one balancing authority area but deliver power to another balancing authority area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. As a result, the net interchange in this table does not match the interchange values shown in Figure 8-1 and Figure 8-2 and Table 8-1 through Table 8-12.

66 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

67 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and LCA after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008)

Table 8-17 Net scheduled and actual PJM flows by interface pricing point (GWh): Calendar year 2011

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
IMO	0	4,864	(4,864)	(100.0%)
LINDENVFT	(1,061)	(1,061)	0	0.0%
MISO	(10,932)	(19,095)	8,164	(42.8%)
NEPTUNE	(4,317)	(4,317)	0	0.0%
NORTHWEST	(2,278)	(58)	(2,220)	3,798.2%
NYIS	(5,772)	(6,900)	1,129	(16.4%)
OVEC	7,667	11,695	(4,028)	(34.4%)
SOUTHIMP/EXP	9,117	7,802	1,315	16.9%
CPLEEXP	0	(648)	648	(100.0%)
CPLEIMP	0	30	(30)	(100.0%)
DUKEXP	0	(2,339)	2,339	(100.0%)
DUKIMP	0	1,076	(1,076)	(100.0%)
NCMPAEXP	0	0	0	0.0%
NCMPAIMP	0	592	(592)	(100.0%)
SOUTHEXP	0	(1,838)	1,838	(100.0%)
SOUTHIMP	9,117	11,185	(2,068)	(18.5%)
SOUTHWEST	0	(257)	257	(100.0%)
Total	(7,576)	(7,072)	(504)	7.1%

The IMO Interface Pricing Point was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a one-to-one mapping could not be created. PJM created the IMO Interface Pricing Point that reflects the power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO Interface Pricing Point does not have physical ties with PJM. As a result, actual flows associated with the IMO Interface Pricing Point are zero. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Some variability can be expected between the scheduled and actual flows at interface pricing points. This is due to the fact that the topology of the transmission system is constantly changing with transmission and generation outages. Large deviations between scheduled and actual flows on an interface pricing point, with the exception of the IMO pricing point, may reflect the fact that some generating and load balancing authorities are mapped to an interface that does not correspond to the actual flows, and therefore, are priced incorrectly. The MMU recommends that PJM perform a regular assessment of the mappings associated with the interface pricing points and the weights applied to the components of the interfaces, and modify as necessary to reflect current system topology in order to ensure that transactions are priced based on the actual flows that they create on the transmission system.

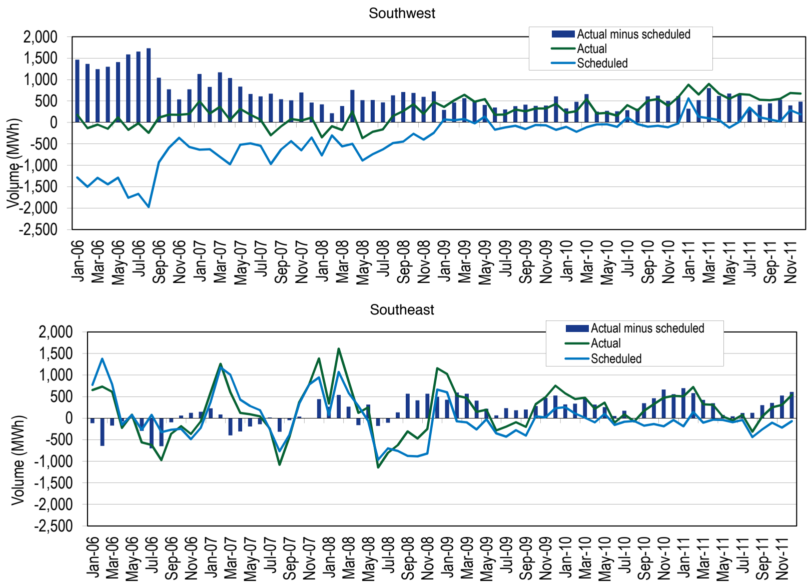
Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As it had in 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-16,913 GWh in 2011 and -15,106 GWh in 2010), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (3,840 GWh in 2011 and 4,015 GWh in 2010). The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

Loop Flows at PJM's Southern Interfaces

Figure 8-10 illustrates the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, a market participant requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the real-time LMP at the Southeast pricing points and the SouthEXP pricing point was $2.14 in 2011 and the average difference between the real-time LMP at the Southwest pricing points and the SouthEXP pricing point was -$1.94 in 2011. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) The MMU recommended that these grandfathered agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing.

Figure 8-10 Southwest and southeast actual and scheduled flows: January 2006 through December 2011



As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities. These agreements expired on January 31, 2012 and have not been renewed. The MMU recommends that PJM not enter into any such special pricing agreements.

Despite some improvements, significant loop flows persist. While the SouthIMP and SouthEXP pricing points have replaced the Southeast and Southwest pricing points Figure 8-10 is included for comparison.

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match prices with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 7.1 percent in 2011, much greater differences existed at individual interfaces.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.[68]

The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. The MMU has been attempting to obtain access to this data for several years without success. Attempts to obtain the data from NERC or tagging vendors have led to denials or to the option of very expensive subscriptions that would still require obtaining approval from every entity registered in the NERC Transmission System Information Network (TSIN) due to data confidentiality agreements, including Transmission Providers and Market Participants.

On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.[69] On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.[70] As of December 31, 2011, the Commission had not made a final rulemaking decision on this proposal.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called fewer TLRs in 2011 than in 2010. The fact that PJM has issued only 62 TLRs in 2011, compared to 110 in 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs decreased by 44 percent, from 110 during 2010 to 62 in 2011 (Table 8-19). In addition, the number of different flowgates for

68 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for a more complete description of the data needed.

69 See 135 FERC ¶ 61,052 (2011).

70 See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

which PJM declared TLRs decreased from 28 in 2010 to 18 in 2011. The total MWh of transaction curtailments decreased by 46 percent, from 315,435 MWh in 2010 to 171,221 MWh in 2011. Of the 62 TLRs called by PJM in 2011, two facilities comprised 43 percent of the total. The two facilities were:

- **2419 Danville – E Danville 138 kV line for the loss of Jacksons Ferry – Antioch 500 kV line.** This line is located in southern Virginia. In 2011, TLRs on this flowgate were used to control constraints created by forced outages of nearby facilities due to storm damage (18 TLRs in 2011; 22 TLRs in 2010);

Table 8-18 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2011

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562

Table 8-19 PJM and MISO TLR procedures: Calendar years 2010 and 2011[71]

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	4	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
Oct-11	4	16	2	6	16,812	27,392
Nov-11	0	10	0	5	0	22,672
Dec-11	0	5	0	3	0	8,659

- **310 Person – Halifax 230 kV for the loss of Wake – Carson 500 kV.** This line is also located in southern Virginia. In 2011, TLRs were used on this flowgate to control constraints created by changes in load and generation patterns due to extreme weather (9 TLRs in 2011; 12 TLRs in 2010).

MISO called significantly fewer TLRs in 2011 than in 2010. MISO TLRs decreased by 43 percent, from 249 in 2010 to 141 in 2011 (Table 8-19).

Table 8-18 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix E "Interchange Transactions" of this document. In 2011, PJM issued 62 transmission loading relief procedures (TLRs). Of the 62 TLRs issued, the highest levels reached were TLR 3a in 34 instances and TLR 3b in the remaining 28 events (2010 totals were 65 TLR 3a, 45 TLR 3b, 0 TLR 4 and 0 TLR 5b).

Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.

An up-to congestion transaction is analogous to a matched set of incremental offers (INC) and decrement bids (DEC) that are evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like a DEC bid and the sink specified on the OASIS reservation looks like an INC offer. For export transactions, the specified source on the OASIS reservation looks like a DEC bid, and the export pricing point looks

71 The curtailment volume for PJM TLR's was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLR's was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx>.

like an INC offer. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like a DEC bid, and the export pricing point specified looks like an INC offer. In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. Conversely, an up-to congestion export transaction is submitted and modeled as a withdrawal at the interface, and an injection at a specific PJM node. Wheel through up-to congestion transactions are modeled as an injection at the importing interface and a withdrawal at the exporting interface.

While an up-to congestion bid is analogous to a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, is not subject to day-ahead or balancing operating reserve charges and does not have clear rules governing credit requirements. Additionally, effective September 17, 2010, up-to congestion transactions are no longer required to pay for transmission, which, prior to that time, was the only cost of submitting an up-to congestion transaction not incurred by a matched pair of INC offers and DEC bids.

Prior to the May 15, 2010, modification to the marginal loss surplus allocation, the average daily volume of up-to congestion transactions was 4,269 bids per day (March 1, 2009 through May 14, 2010).[72] The average daily volume of up-to congestion transactions increased to 6,881 bids per day for the period between the initial May 15, 2010, modification and the additional modification to the marginal loss surplus allocation methodology made on September 17, 2010. The average daily volume of up-to congestion bids further increased to 26,303 bids per day following the additional modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids, which was implemented as part of the September 17, 2010 marginal loss surplus allocation methodology changes (September 17, 2010, through December 31, 2011). (See Figure 8-11and Table 8-20.)

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions.

The MMU recommends that the up-to congestion transaction product be eliminated. This product could work as a derivative product traded outside PJM markets and without any of these impact on the actual operation of PJM markets. Alternatively, the MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges and to make appropriate provisions for credit. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding for all import and export transactions in the Day-Ahead Energy Market. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

Effective May 16, 2011, for the May 17, 2011, Day-Ahead Market, PJM modified the available locations for up-to congestion transactions to eliminate the ability to submit up-to congestion bids at the CPLEIMP, CPLEEXP, DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP Interface pricing points. These interface pricing points were eliminated to avoid wheeling up-to congestion transactions from being submitted at the same interface to arbitrage price differentials between the Day-Ahead and Real-Time Energy Markets created by existing JOA's (for example, using an import pricing point of CPLEIMP and an export pricing point of CPLEEXP or SouthEXP). The MMU agrees with the elimination of these interfaces for up-to congestion transactions, as

72 In prior state of the market reports for PJM, the number of bids reported represented unique up-to congestion bids. The new totals represent the total hours of up-to congestion bids per day. For example, if a unique up-to congestion transaction spanned all 24 hours of the day, it would have counted as one bid in previous reports, and now is counted as 24 bids.

wheeling transactions at the same interface are not permitted in the Real-Time Energy Market.

The up-to congestion transactions in 2011 were comprised of 54.1 percent imports, 44.2 percent exports and 1.7 percent wheeling transactions. Only 0.2 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions. Of the up-to congestion transactions with matching Real-Time Energy Market transactions, 0.5 percent were imports, 93.7 percent were exports and 5.9 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Energy Market transactions, 19.8 percent of such cleared transaction MW were profitable in 2011. The net loss on all these transactions was approximately $4.0 million. When up-to congestion transactions did not have a matching Real-Time Energy Market transaction, 48.0 percent of such cleared transaction MW were profitable. The net profit on all these transactions was approximately $110.3 million.

Figure 8-12 shows the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 8-12 shows the physical transactions on a different scale than the financial transactions. There is such a small number of physical transactions that the results would not be visible on the scale of the financial chart.

Figure 8-11 Monthly up-to congestion cleared bids in MWh: January 2006 through December 2011

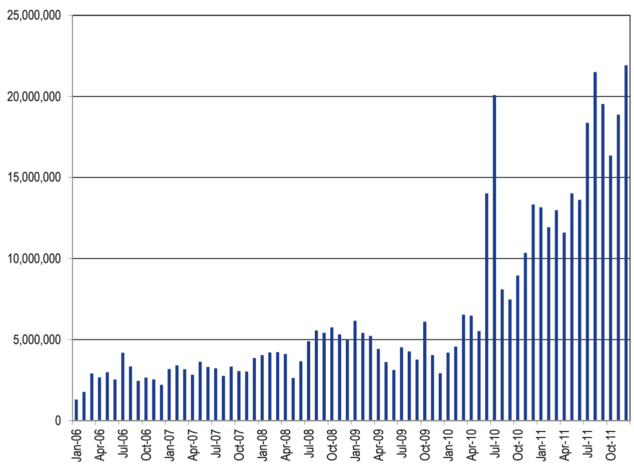
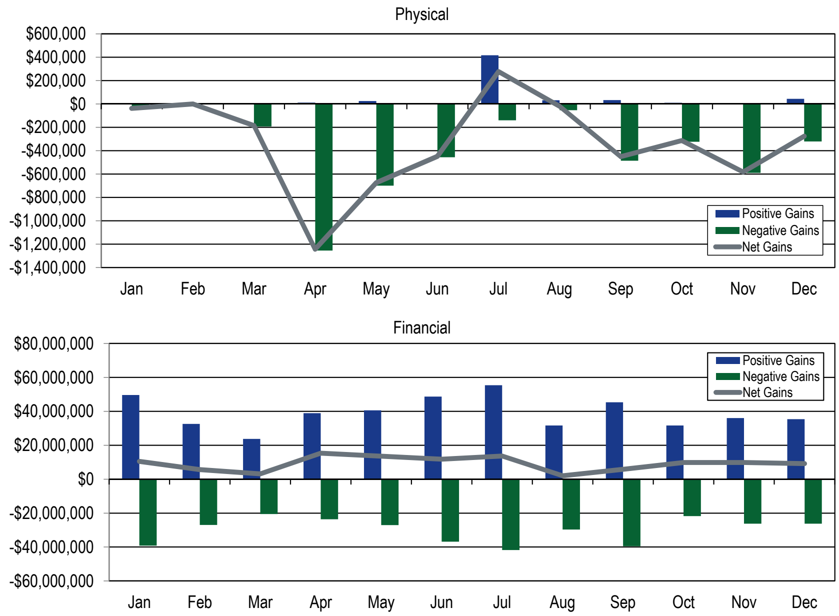


Table 8-20 Monthly volume of cleared and submitted up-to congestion bids: Calendar years 2009 through 2011

	Bid MW				Bid Volume				Cleared MW				Cleared Volume			
Month	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total
Jan-09	4,218,910	5,787,961	319,122	10,325,993	90,277	74,826	6,042	171,145	2,591,211	3,242,491	202,854	6,036,556	56,132	45,303	4,210	105,645
Feb-09	3,580,115	4,904,467	318,440	8,803,022	64,338	70,874	6,347	141,559	2,374,734	2,836,344	203,907	5,414,985	42,101	44,423	4,402	90,926
Mar-09	3,649,978	5,164,186	258,701	9,072,865	64,714	72,495	5,531	142,740	2,285,412	2,762,459	178,507	5,226,378	42,408	42,007	4,299	88,714
Apr-09	2,607,303	5,085,912	73,931	7,767,146	47,970	67,417	2,146	117,533	1,797,302	2,582,294	48,478	4,428,074	32,088	35,987	1,581	69,656
May-09	2,196,341	4,063,887	106,860	6,367,088	40,217	54,745	1,304	96,266	1,496,396	2,040,737	77,553	3,614,686	26,274	29,720	952	56,946
Jun-09	2,598,234	3,132,478	164,903	5,895,615	47,625	44,755	2,873	95,253	1,540,169	1,500,560	88,723	3,129,452	28,565	23,307	1,522	53,394
Jul-09	3,984,680	3,776,957	296,910	8,058,547	67,039	56,770	5,183	128,992	2,465,891	1,902,807	163,129	4,531,826	41,924	31,176	2,846	75,946
Aug-09	3,551,396	4,388,435	260,184	8,200,015	64,652	64,052	3,496	132,200	2,278,431	2,172,133	194,415	4,644,978	41,774	34,576	2,421	78,771
Sep-09	2,948,353	4,179,427	156,270	7,284,050	51,006	64,103	2,405	117,514	1,774,589	2,479,898	128,344	4,382,831	31,962	40,698	1,944	74,604
Oct-09	3,172,034	6,371,230	154,825	9,698,089	46,989	100,350	2,217	149,556	2,060,371	3,931,346	110,646	6,102,363	31,634	70,964	1,672	104,270
Nov-09	3,447,356	3,851,334	103,325	7,402,015	53,067	61,906	1,236	116,209	2,065,813	1,932,595	51,929	4,050,337	33,769	32,916	653	67,338
Dec-09	2,323,383	2,502,529	66,497	4,892,409	47,099	47,223	1,430	95,752	1,532,579	1,359,936	34,419	2,926,933	31,673	28,478	793	60,944
Jan-10	3,794,946	3,097,524	212,010	7,104,480	81,604	55,921	3,371	140,896	2,250,689	1,789,018	161,977	4,201,684	49,064	33,640	2,318	85,022
Feb-10	3,841,573	3,937,880	316,150	8,095,603	80,876	80,685	2,269	163,830	2,627,101	2,435,650	287,162	5,349,913	50,958	48,008	1,812	100,778
Mar-10	4,877,732	4,454,865	277,180	9,609,777	97,149	74,568	2,239	173,956	3,209,064	3,071,712	263,516	6,544,292	60,277	48,596	2,064	110,937
Apr-10	3,877,306	5,558,718	210,545	9,646,569	67,632	85,358	1,573	154,563	2,622,113	3,690,889	170,020	6,483,022	42,635	54,510	1,154	98,299
May-10	3,800,870	5,062,272	149,589	9,012,731	74,996	78,426	1,620	155,042	2,366,149	3,049,405	112,700	5,528,253	47,505	48,996	1,112	97,613
Jun-10	9,126,963	9,568,549	1,159,407	19,854,919	95,155	89,222	6,960	191,337	6,863,803	6,850,098	1,072,759	14,786,660	59,733	55,574	5,831	121,138
Jul-10	12,818,141	11,526,089	5,420,410	29,764,640	124,929	106,145	18,948	250,022	8,971,914	8,237,557	5,241,264	22,450,734	73,232	60,822	16,526	150,580
Aug-10	8,231,393	6,767,617	888,591	15,887,601	115,043	87,876	10,664	213,583	4,430,832	2,894,314	785,726	8,110,871	62,526	40,485	8,884	111,895
Sep-10	7,768,878	7,561,624	349,147	15,679,649	184,697	161,929	4,653	351,279	3,915,814	3,110,580	256,039	7,282,433	63,405	45,264	3,393	112,062
Oct-10	8,732,546	9,795,666	476,665	19,004,877	189,748	154,741	7,384	351,873	4,150,104	4,564,039	246,594	8,960,736	76,042	65,223	3,670	144,935
Nov-10	11,636,949	9,272,885	537,369	21,447,203	253,594	170,470	9,366	433,430	5,765,905	4,312,645	275,111	10,353,661	112,250	71,378	4,045	187,673
Dec-10	17,769,014	12,863,875	923,160	31,556,049	307,716	215,897	15,074	538,687	7,851,235	5,150,286	337,157	13,338,678	136,582	93,299	7,380	237,261
Jan-11	20,275,932	11,807,379	921,120	33,004,431	351,193	210,703	17,632	579,528	7,917,986	4,925,310	315,936	13,159,232	151,753	91,557	8,417	251,727
Feb-11	18,418,511	13,071,483	800,630	32,290,624	345,227	226,292	17,634	589,153	6,806,039	4,879,207	248,573	11,933,818	151,003	99,302	8,851	259,156
Mar-11	17,330,353	12,919,960	749,276	30,999,589	408,628	274,709	15,714	699,051	7,104,642	5,603,583	275,682	12,983,906	178,620	124,990	7,760	311,370
Apr-11	17,215,352	9,321,117	954,283	27,490,752	513,881	265,334	17,459	796,674	7,452,366	3,797,819	351,984	11,602,168	229,707	113,610	8,118	351,435
May-11	21,058,071	11,204,038	2,937,898	35,200,007	562,819	304,589	24,834	892,242	8,294,422	4,701,077	1,031,519	14,027,018	261,355	143,956	11,116	416,427
Jun-11	20,455,508	12,125,806	395,833	32,977,147	524,072	285,031	12,273	821,376	7,632,235	5,361,825	198,482	13,192,543	226,747	132,744	6,363	365,854
Jul-11	24,273,892	16,837,875	409,863	41,521,630	603,519	338,810	13,781	956,110	9,585,027	8,617,284	205,599	18,407,910	283,287	186,866	7,008	477,161
Aug-11	23,790,091	21,014,941	229,895	45,034,927	591,170	403,269	8,278	1,002,717	10,594,771	10,875,384	103,141	21,573,297	274,398	208,593	3,648	486,639
Sep-11	21,740,208	18,135,378	232,626	40,108,212	526,945	377,158	7,886	911,989	10,219,806	9,270,121	82,200	19,572,127	270,088	185,585	3,444	459,117
Oct-11	20,240,161	19,476,556	333,077	40,049,794	540,877	451,507	8,609	1,000,993	8,376,208	7,853,947	126,718	16,356,873	255,206	198,778	4,236	458,220
Nov-11	27,007,141	28,994,789	507,788	56,509,718	594,397	603,029	13,379	1,210,805	9,064,570	9,692,312	131,670	18,888,552	254,851	256,270	5,686	516,807
Dec-11	34,990,790	34,648,433	531,616	70,170,839	697,524	655,222	14,187	1,366,933	11,738,910	10,049,685	137,689	21,926,284	281,304	248,008	6,309	535,621
TOTAL	401,350,403	352,234,122	22,204,096	775,788,621	8,618,384	6,536,407	295,997	15,450,788	184,074,602	163,527,346	13,902,119	361,504,067	4,092,832	3,115,609	166,440	7,374,881

Figure 8-12 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction (physical) and without a matching Real-Time Energy Market transaction (financial): Calendar year 2011



Of all the market participants that utilize up-to congestion transactions, the top five participants accounted for 55.9 percent of all cleared transactions and the top ten participants accounted for 72.1 percent of all cleared transactions. The top five participants that experienced losses accounted for 50.2 percent of all the losses, and the top ten participants that experienced losses accounted for 68.5 percent of all the losses on those bids.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the southeast and southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[73] Table 8-21 shows the historical differences in Real-Time Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences, but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[74] Progress Energy Carolinas, February 13, 2007;[75] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[76]

There were a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate, and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

73 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx>.

74 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx>. (Accessed March 1, 2012)

75 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (Accessed March 1, 2012).

76 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx>. (Accessed March 1, 2012)

Table 8-21 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: Calendar years 2007 through 2011

Year	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.00)
2008	$62.97	$51.42	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.02)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$43.46	$36.27	$39.29	$39.14	$4.17	($3.02)	$4.32	($2.87)
2011	$40.77	$36.69	$38.63	$38.63	$2.14	($1.94)	$2.14	($1.94)

Table 8-22 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2011

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$39.05	$40.01	$38.63	$38.63	$0.42	$1.38
PEC	$39.73	$41.43	$38.63	$38.63	$1.10	$2.80
NCMPA	$39.59	$39.73	$38.63	$38.63	$0.96	$1.10

On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[77,78] On January 20, 2011, the Commission issued an Order conditionally accepting the compliance filing submitted by PJM and PEC.[79] The parties meet on a yearly basis, and, in 2011, there were no developments. On May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.[80] The agreement remained in effect in 2011.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology as defined in the PJM Tariff.[81] Under the marginal cost proxy pricing methodology, the price for imports of energy to PJM from the external balancing authority area is the LMP, calculated by PJM, of the lowest priced generator bus in the external balancing authority area that has an output greater than zero and is less than its marginal cost. If no generator, with an output greater than zero, has an LMP less than its marginal cost, the import price is calculated as the average of the bus LMPs for the set of generators that PJM determines to be moving to support the import transaction. Conversely, the price for exports of energy from PJM to the external balancing authority area is the LMP, calculated by PJM, of the highest priced generator bus in the external balancing authority area that has an output greater than zero and is greater than its marginal cost (excluding nuclear and hydro units). If no generator, with an output greater than zero, has an LMP greater than its marginal cost, the export price is calculated as the average of the bus LMPs for the set of generators that PJM determines to be moving to support the export transaction. The LMPs under this methodology are calculated every five minutes and aggregated on an hourly basis in the Real-Time Energy Market, and are calculated for each hour in the Day-Ahead Energy Market. These pricing points are only eligible during hours where the entity importing energy into PJM can confirm that the source of the energy is in the neighboring balancing authority, or where the entity exporting energy out of PJM can confirm that the sink of the energy is in the neighboring balancing authority.

The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff. Under the high-low pricing methodology, the price for imports of energy to PJM from the external balancing authority area is the LMP, calculated by PJM, at the lowest priced generator bus in the external balancing authority area that has an output greater than zero. Conversely, the price for exports of energy from PJM to the external balancing authority area is the LMP, calculated by PJM, at the highest priced generator bus in the external balancing authority area that has an output greater than zero. The LMPs under this methodology are calculated every five minutes and

77 See PJM Interconnection, L.L.C., and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

78 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

79 134 FERC ¶ 61,048 (2011).

80 PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc., Docket No. ER11-3637-000 (May 25, 2011)

81 See PJM Interconnection, L.L.C, Docket No. ER10-2710-000 (September 17, 2010).

Figure 8-13 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2011

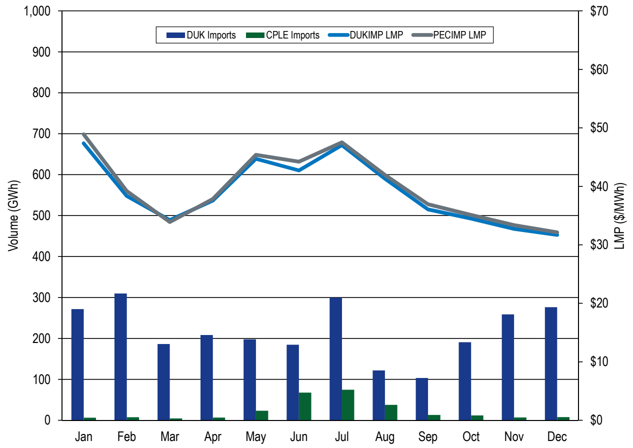
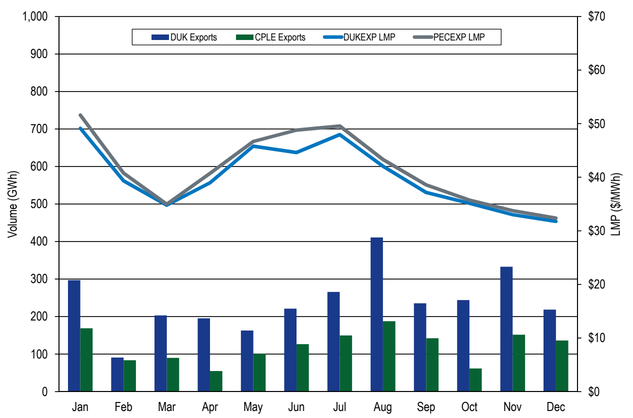


Figure 8-14 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2011



aggregated on an hourly basis in the Real-Time Energy Market, and are calculated for each hour in the Day-Ahead Energy Market. These pricing points are only eligible during hours where the entity importing energy into PJM can confirm that the source of the energy is in the neighboring balancing authority, or where the entity exporting energy out of PJM can confirm that the sink of the energy is in the neighboring balancing authority.

Table 8-22 shows the real-time LMP calculated per the revised PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2011. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.42 with Duke to $1.10 with PEC.[82] This means that under the specific interface pricing agreements, Duke receives, on average, $0.42 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $1.10 with NCMPA to $2.80 with PEC. This means that under the specific interface pricing agreements, Duke pays, on average, $1.38 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

Table 8-23 shows the historical differences in Day-Ahead Energy Market LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation.

Table 8-24 shows the day-ahead LMP calculated per the revised PJM/PEC JOA and the high/low pricing methodology used by Duke and NCMPA for the calendar year 2011. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.81 with Duke to $1.73 with PEC.[83] This means that under the specific interface pricing agreements, Duke receives, on average, $0.81 more for importing energy into PJM than they would have if they were to receive the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $1.85 with NCMPA to $3.79 with PEC. This means that under the specific interface pricing agreements, Duke pays, on average, $1.85 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point.

82 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

83 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 8-23 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: Calendar years 2007 through 2011

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$44.42	$36.76	$39.40	$39.40	$5.03	($2.63)	$5.03	($2.63)
2011	$41.27	$37.34	$38.69	$38.69	$2.58	($1.35)	$2.57	($1.36)

Table 8-24 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2011

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$39.50	$41.14	$38.69	$38.69	$0.81	$2.45
PEC	$40.42	$42.48	$38.69	$38.69	$1.73	$3.79
NCMPA	$39.90	$40.54	$38.69	$38.69	$1.21	$1.85

Figure 8-15 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2011

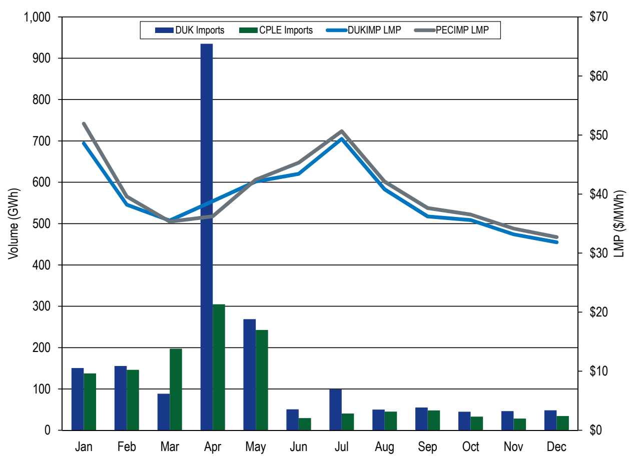
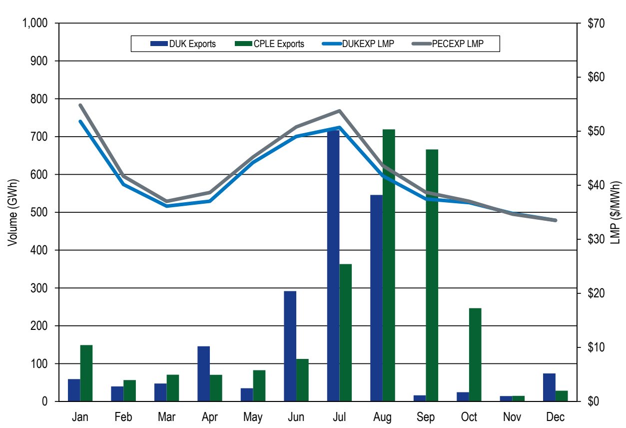


Figure 8-16 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2011



Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

Total uncollected congestion charges during the calendar year 2011 were -$20,955, compared to $3.3 million in 2010 (Table 8-25). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in 2011. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP at the source is greater than the LMP at the sink. The fact that there was a total negative congestion collection in 2011, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

Table 8-25 Monthly uncollected congestion charges: Calendar years 2010 and 2011

Month	2010	2011
Jan	$148,764	$3,102
Feb	$542,575	$1,567
Mar	$287,417	$0
Apr	$31,255	$4,767
May	$41,025	$0
Jun	$169,197	$1,354
Jul	$827,617	$1,115
Aug	$731,539	$37
Sep	$119,162	$0
Oct	$257,448	($31,443)
Nov	$30,843	($795)
Dec	$127,176	($659)
Total	$3,314,018	($20,955)

Elimination of Sources and Sinks

The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[84] These modifications are currently being evaluated by PJM to develop an implementation plan.

Until the internal source and sink designations are eliminated from the external energy transactions in the Day-Ahead Energy Market, the MMU continues to recommend that PJM require that all import and export up-to congestion transactions pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserve charges.

Spot Import

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM interpreted its JOA with MISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[85] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. Spot import service (a

84 See "Meeting Minutes" Minutes from PJM's MIC meeting (May 16, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>. (Accessed on March 1, 2012)

85 See "Modifications to the Practices of Non-Firm and Spot market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>. (Accessed March 1, 2012)

network service) is provided at no charge to the market participant offering into the PJM spot market.

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[86] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and two hours when queued the day prior. On June 23, 2009 PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage (defined as scheduling) has been over 99 percent, compared to 70 percent prior to the modification (Figure 8-17).

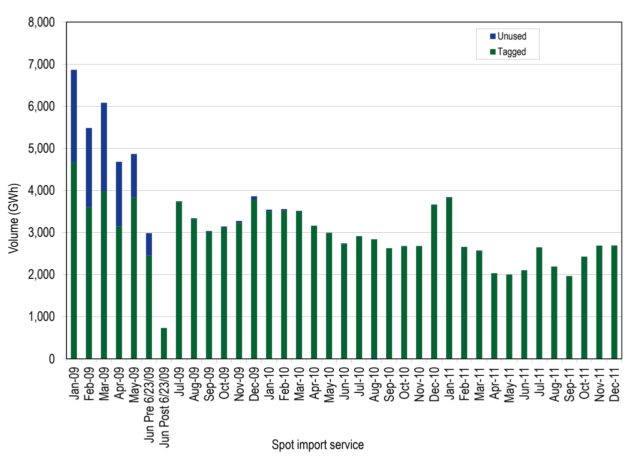
Although the rule change resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service. In 2010, market participants were still unable to acquire spot import service on the NYIS-PJM path when it was not being used to flow energy. The MMU found that the bidding process in the NYISO resulted in market participants reserving and scheduling but not using transmission to flow energy.

At the December 7, 2010, meeting of the Market Implementation Committee (MIC), PJM and the MMU made a joint recommendation to return to unlimited ATC for non-firm willing to pay congestion service on all paths for all non-firm willing to pay congestion transmission service. The PJM Stakeholders agreed with recommendation.

PJM reported that further modifications to the various JOAs would be required to revert to unlimited ATC for non-firm willing to pay congestion service. To modify the JOA, both parties must be in agreement with any proposed changes. PJM reported that MISO and Progress Energy Carolinas, Inc., counterparties to two JOAs, expressed concerns about allowing for unlimited ATC, citing potential reliability concerns, and were unwilling to make the modifications.

As an alternative to creating an unlimited amount of ATC, PJM suggested including a utilization factor in the ATC calculation for non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. For example, if a path has 1,000 MW of ATC available, and the utilization factor is sixty percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 400 MW of ATC available to be requested. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

Figure 8-17 Spot import service utilization: Calendar years 2010 and 2011



86 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) <http://www.pjm.com/markets-and-operations/etools/~/media/etools/oasis/regional-practices-redline-doc.ashx>. (Accessed March 1, 2012)

Real-Time Dispatchable Transactions

Dispatchable transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Import dispatchable transactions receive the hourly integrated import pricing point LMP for the hours when energy flows. If the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

Dispatchable transactions were initially a valuable tool for market participants. Currently, real-time LMPs are readily available to market participants, and the timing requirement for submitting transactions has been reduced to 20 minutes notification. The value that dispatchable transactions once provided market participants no longer exists but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits. In 2011, $1.3 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions compared to $23.0 million for the calendar year 2010.

Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were $1.3 million, a decrease from $23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011.

The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the PJM dispatch tool, the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. Including dispatchable transactions in the ITSCED application allows them to be evaluated and included in the economic dispatch along with generator bids, and removes the guesswork for the PJM dispatch on whether the transaction is likely to be economic in the next hour. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.[87] PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in 2012.

Internal Bilateral Transactions

In the third quarter of 2011, it was discovered that a number of companies had used internal bilateral transactions to improperly reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with virtual positions taken in the PJM Day-Ahead Market.[88] Use of IBTs in this manner was improper because these transactions, designed to offset virtual positions, do not "contemplate the physical transfer of energy," as the market rules require.[89]

At the PJM Markets Implementation Committee, held on November 1, 2011, PJM submitted the following issue charge:

87 See "Meeting Minutes" Minutes from PJM's MIC meeting (July 13, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx> (Accessed on March 1, 2012).

88 See Comments of the Independent Market Monitor for PJM in Docket No. EL12-8-000 (December 2, 2011); see also Complaint of DC Energy and DC Energy Mid-Atlantic, LLC in Docket No. EL12-8-000, Attachment A (October 20,2011 PJM Notification) (October 28, 2011).

89 PJM Operating Agreement Schedule 1 § 1.7.10.

> Under the current rules for Balancing Operating Reserve (BOR) deviation calculations, deviations are netted by transaction type (INC, DEC, import, export, internal bilateral purchase or sale) at the location where there transaction occurred (ie Hub, Zone, Interface, Aggregate, bus). This rule was retained on a locational basis when the package of BOR changes was implemented in December of 2008 in order to recognize that deviations at differing locations on the system can impact BOR costs. PJM has identified and documented activity by market participants whereby Internal Bilateral Transactions (IBTs) may have been submitted in order to inappropriately avoid BOR charges. PJM believes the potential for using IBTs in this manner extends beyond the behavior that PJM has already identified. PJM therefore recommends that stakeholders revisit the netting rule and explore potential improvements to eliminate the potential for inappropriate use of IBTs.[90]

The PJM stakeholders unanimously approved the issue charge to evaluate the BOR netting rules. This issue is currently being addressed at FERC and through the PJM stakeholder process.[91]

90 See "Investigation of Balancing Operating Reserve Netting Rules" from PJM's MIC meeting (November 1, 2011) <http://www.pjm.com/~/media/committees-groups/committees/mic/20111101/20111101-item-03a-investigation-of-bor-netting-rules-presentation.ashx> (Accessed on March 1, 2012).

91 DC Energy, LLC and DC Energy Mid-Atlantic, LLC v. PJM Interconnection, L.L.C., Docket No. EL12-8-000 (October 28, 2011).

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

The purpose of the Day-Ahead Scheduling Reserve (DASR) market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.[3]

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for 2011.

Table 9-1 The Regulation Market results were not competitive[4]

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 82 percent of the hours in 2011.

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See the *2011 State of the Market Report for PJM*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2011.

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

4 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[5]

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 9-2 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 63 percent of the hours in 2011.

- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 9-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 13 percent of offers reflected economic withholding, with offer prices above $5.00.

- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.

- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market in 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008, when PJM implemented four changes to the Regulation Market: introducing the three pivotal supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits.[6]

5 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

6 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

Market Structure

- **Supply.** In 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.00 for 2011. This is a 1.7 percent increase over 2010 when the ratio was 2.95.

  Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, other rules (a minimum offer requirement of 1 MW as well as the prohibition of demand resources offering both economic and emergency demand reduction combined with a prohibition of a demand resource being represented by more than one CSP) made it impractical. On November 21, 2011, these rules were modified and the first two demand resources offered and cleared regulation.

- **Demand.** The on-peak regulation requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2011 was 925 MW (842 MW off peak, and 1,017 MW on peak). This is a 32 MW increase in the average hourly regulation demand of 893 MW in 2010 (811 MW off peak, and 981 MW on peak).

  Of the LSEs' obligation to provide regulation during 2011, 81.8 percent was purchased in the spot market (82.2 percent in 2010), 15.6 percent was self scheduled (15.5 percent in 2010), and 2.6 percent was purchased bilaterally (2.3 percent in 2010).

- **Market Concentration.** In 2011, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1630 which is classified as "moderately concentrated."[7] The minimum hourly HHI was 818 and the maximum hourly HHI was 4005. The largest hourly market share in any single hour was 58.9 percent, and 84.3 percent of all hours had a maximum market share greater than 20 percent.[8] In 2011, 82.1 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (73.3 percent of hours failed the three pivotal supplier test in 2010). The MMU concludes from these results that the PJM Regulation Market in 2011 was characterized by structural market power in 82.1 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers also apply for the entire day and remain subject to the $100 per MWh offer cap.[9] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then cleared again.

Market Performance

- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market in 2011 was $16.21 per MW. This was a decrease of $1.87, or 10 percent, from the weighted average price for regulation in 2010. The total cost of regulation decreased by $2.79 from $32.07 per MW in 2010, to $29.28, or

7 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

8 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

9 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012) p. 55.

8.7 percent. In 2011 the weighted Regulation Market clearing price was only 55 percent of the total regulation cost per MW, compared to 56 percent of the total costs of regulation per MW in 2010. The difference between the total cost of regulation and the clearing price of regulation was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP. In addition, units scheduled to regulate are, at times, switched with other units in an owner's fleet of regulation units by the owner or at the direction of PJM Dispatch as a result of binding constraints or performance problems.

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

The integration of the Trans-Allegheny Line (TrAIL) project (performed in three stages April 8, May 13, and May 20, 2011) resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market.[10] That interface had been the AP South interface since March 2009. After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface and remained so throughout 2011. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.[11] From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is also available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. Since then, PJM has changed the transfer capacity several times varying from 50 percent to 15 percent at the end of 2011. The higher the assumed transfer capability, the greater the supply of Tier 1 that is available from west of the interface to meet synchronized reserve requirements in the Mid-Atlantic subzone. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. These changes to the transfer interface capacity did affect the Synchronized Reserve Market by changing the amount of Tier 2 required in the Mid-Atlantic Subzone. Synchronized reserves added out of market were 1.6 percent of all synchronized reserves in 2011, down from 3.4 percent in 2010.[12] After-market opportunity cost payments accounted for 16.8 percent of total costs in 2011 compared to 26.8 percent in 2010.

Market Structure

- **Supply.** In 2011 the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the administrative synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.[13] This is a six percent decrease from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in 2011 was 2.89 for the Mid-Atlantic Subzone. The ratio of offered and eligible synchronized reserve to the required Tier 2 was 3.00 for the RFC Zone for all hours in which a Tier 2 market was cleared. This is an 11 percent increase from 2010 when the ratio was 2.68. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

10 PJM.com "TrAIL Operational Impacts," <http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx> (October 2011).

11 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

12 This figure was incorrectly reported as "five percent" in *2010 State of the Market Report for PJM*, Section 6, "Ancillary Service Markets", p.423.

13 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

- **Demand.** PJM made no changes to the default hourly required synchronized reserve requirements in 2011. The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011, for double spinning, and was raised to 1,760 MW on May 3, 4, 5 and 6 for double spinning. On September 7 the Synchronized Reserve requirement was raised to 1,700 MW for most of the day for double spinning. Table 9-20 lists all spinning events from January 2009 through December 2011.

  In 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 83 percent of hours. This is a 24 percent increase from 2010, when the market cleared in 67 percent of hours. In 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 527 MW. In 2010 the average required Tier 2 synchronized reserve was 358 MW.

  Synchronized reserves added out of market were 1.6 percent of all Mid-Atlantic Subzone synchronized reserves in 2011. Synchronized reserves added out of market were 3.4 percent of all Mid-Atlantic Subzone synchronized reserves in 2010.

  Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent (16 hours) cleared a Tier 2 Synchronized Reserve Market in the RFC in 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in 26 hours in 2011.

- **Market Concentration.** The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[14] For purchased synchronized reserve (cleared plus added) the HHI was 2675. In 2011, 46 percent of hours had a maximum market share greater than 40 percent, compared to 68 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in 2011, 63 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2010, 62 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in 2011 was characterized by structural market power.

14 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

  Total MW of cleared demand side resources increased in 2011 over 2010 (from 613,762 MW to 982,434 MW). The DSR share of the total Synchronized Reserve Market increased from 16.5 percent in 2010 to 17.7 percent in 2011. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 6.6 percent of hours in 2011 compared to 8.0 percent of hours in 2010.

- **Compliance.** The MMU has reviewed synchronized reserve non-compliance between 2009 and 2011 and concluded that the incentive/penalty structure is not adequate. Although providers of Tier 2 synchronized reserve are paid for making synchronized reserve MW available every hour, it is only during spinning events that such Tier 2 synchronized reserve is actually used. The result is that it is possible to provide the service profitably with a very low level of compliance. This behavior does exist in this market. PJM's synchronized reserve penalty structure fails to penalize this behavior adequately. The MMU recommends that the Synchronized Reserve Market non-compliance penalties be restructured to address this issue and provide stronger incentives for compliance.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $11.81 per MW in 2011, a $1.26 per MW increase from 2010. The total cost of synchronized reserves per MWh in 2011 was $15.48, a $1.07 increase (7.4 percent) from the $14.41 cost of synchronized reserve in 2010. The market clearing price was 76 percent of the total synchronized reserve cost per MW in 2011, up from 73 percent in 2010.

The difference between the total cost of synchronized reserve and the clearing price of synchronized reserve can be attributed to two factors. Using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of synchronized reserve include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

PJM changed the estimates of Tier 1 reserves over a wide range in 2011, without providing an explanation of the determinants of Tier 1 reserves. These estimates have a significant impact on the market.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[15] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[16] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** In 2011, there were 21 hours in the DASR market which failed the three pivotal supplier test. All 21 hours occurred in June, July and August during periods of high demand. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010.[17] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement was 7.11 percent. The DASR MW purchased averaged 6,500 MW per hour for 2011, an increase from 6,033 MW per hour in 2010.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The marginal cost of providing DASR is zero. In the first five months of 2011, five percent of units offered at $50 or more and four percent offered at more than $900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. Between June 1, and December 31, 2011, thirteen percent of all units offered DASR at levels above $5, while less than one percent of units offered above $50. Two units offered above $900. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[18] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2011.

15 See 117 FERC ¶ 61,331 (2006).

16 See PJM. "Manual 13: Emergency Operations," Revision 47, (January 1, 2011); pp 11-12.

17 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

18 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), pp. 123-124.

Market Performance

- **Price.** The weighted DASR market clearing price 2011 was $0.55 per MW. In 2010, the weighted price of DASR was $0.16 per MW. The increase in the weighted average price per MW of DASR can be attributed to several days of extremely high DASR prices in June, July and August (a maximum price of $217.12 occurred on July 21, 2011). These high prices were primarily the result of high demand and limited supply which created the need for redispatch in the Day-Ahead Energy Market in order to provide DASR. The result was that DASR prices in these hours reflected opportunity costs associated with the redispatch. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. In 56 percent of hours in 2011 the DASR Market Clearing Price was $0.00. Most, 97 percent, DASR clearing prices consist solely of the offer price. For a few of the high price hours the price is composed almost entirely of LOC. For the top 0.5 percent (average clearing price = $86.25) of hours 99.7 percent of the price is determined by opportunity cost. For the bottom 99.5 percent (average clearing price = $0.12) of hours less than two percent of the price is composed of LOC (Figure 9-18).

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[19]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potential providers at the critical locations identified. The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. These rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. In 2011, charges were $13.63 million. This is 37 percent higher than 2010, when total black start service charges were $9.98 million. There was substantial zonal variation. The increased cost of black start in 2011 is attributable to updated Schedule 6A (to the OATT) rates for all units, major refurbishments of black start resources in the BGE zone, and operating reserve charges associated with blacks start resources in the AEP zone. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.

Black start zonal charges in 2011 (including operating reserves for black start units) ranged from $0.04 per MW in the DLCO zone to $0.90 per MW in the BGE zone. Black start costs in the BGE zone increased due to major refurbishments of multiple black start resources. The black start resources were identified as critical assets in BGE's black start restoration plan by PJM and the transmission owner. The resources undergoing major refurbishment through the black start process are recovering capital investment costs to maintain the units as black start resources using the capital recovery factor (CRF) from Schedule 6A rather than the standard incentive rate provided in the tariff for black start resources. During the recovery period the unit's annual Black Start capital cost recovery will be limited to the greater of the black start payments or capacity market revenues but the commitment to provide black start services from the units does not match the obligation of

19 OATT Schedule 1 § 1.3BB.

customers to pay 100 percent of the capital costs of the refurbishment over an accelerated period.[20]

Ancillary Services costs per MW of load: 2001 - 2011

Table 9-4 shows PJM ancillary services costs for 2001 through 2011 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 9-4 History of ancillary services costs per MW of Load: 2001 through 2011

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22	$0.00	$1.07
2002	$0.45	$0.53	$0.21	$0.07	$0.63
2003	$0.50	$0.61	$0.24	$0.14	$0.83
2004	$0.50	$0.60	$0.25	$0.13	$0.90
2005	$0.79	$0.47	$0.26	$0.11	$0.93
2006	$0.53	$0.48	$0.29	$0.08	$0.43
2007	$0.63	$0.47	$0.29	$0.06	$0.58
2008	$0.68	$0.40	$0.31	$0.08	$0.59
2009	$0.34	$0.32	$0.37	$0.05	$0.48
2010	$0.34	$0.38	$0.41	$0.07	$0.73
2011	$0.32	$0.34	$0.42	$0.10	$0.77

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[21] The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in 2011, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

While the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics, CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC

20 PJM.com "Automated Formula Rate Adjustment Process," Revision 0 <http://www.pjm.com/~/media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx> (March 24, 2010).

21 The *2009 State of the Market Report for PJM* provided the basis for this recommendation. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Order.[22] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.[23] PJM is currently working with stakeholders to develop market rules that would result in an optimal, least cost combination of fast and traditional resources. This creates market design challenges, which if resolved, could improve the regulation market.

Overall, the MMU concludes that the Regulation Market results were not competitive in 2011 as a result of the identified market design changes and their implementation. The MMU is hopeful that the opportunity cost can be resolved in 2012 as part of the regulation market redesign. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in 2011. The MMU concludes that the DASR Market results were competitive in 2011.

Detailed Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. MMU summarized and presented to the MIC on September 13, 2011 the deficiencies of the Regulation Market LOC calculation.[24] On January 11, 2012 PJM presented to the MIC a recommendation that energy-related opportunity costs calculations be standardized across all markets, tariffs, and manuals.[25] If implemented as recommended, this would resolve the opportunity cost issue in the Regulation Market.

    — The MMU recommends that the single clearing price for regulation be determined based on the actual LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would thereby make the market price more reflective of the actual costs of providing the service.

    — The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

    — The MMU recommends that the December 1, 2008 modification to the net revenue offset elimination be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that regulation market credits were offset against operating reserve credits prior to December 1, 2008.

    — The MMU recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected.

22 See *2011 State of the Market Report for PJM*, "Appendix F."

23 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011).

24 PJM.com "Regulation Market: Opportunity Cost Issue," MIC, September 14, 2011. <http://www.pjm.com/~/media/committees-groups/committees/mic/20110913/20110914-item-14-definition-of-opportunity-cost.ashx>

25 PJM.com "Consistency of Energy-Related Opportunity Cost Calculations," MIC, January 11, 2012. <http://www.pjm.com/~/media/committees-groups/committees/mic/20110913/20110914-item-14-definition-of-opportunity-cost.ashx>.

- The MMU recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.
- The MMU recommends that PJM improve the documentation it creates and maintains with respect to the detailed processes for clearing the Regulation Market.

- The MMU recommends that the synchronized market price signal be improved and the market rules be made more transparent.
  - The MMU recommends that the single clearing price for synchronized reserves be determined, after the fact, on the actual LMP. This is expected to result in a net increase in payments to providers of synchronized reserves as a result of an increase in the clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the synchronized reserve market as the resulting price of synchronized reserve would internalize some of the costs currently being collected through uplift and would make the more reflective of the actual costs of providing the service.
  - The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market.
- The MMU recommends that PJM modify it penalty rules for non-compliance in the Synchronized R eserve Market to correct the situation of gross non-compliance (less than 30% compliance in every spinning event) operating profitably because the total SRMCP credits can exceed total penalties.
  - Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends mandatory documentation of reasons for Tier 1 deselection as a way to improve transparency.
- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address the identified market power issues.
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. Transmission owners should play an advisory role. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Regulation Market

Market Structure

The market structure of the 2011 PJM Regulation Market remains unchanged since December 1, 2008. The rule changes of December 1, 2008, significantly affected the design of the Regulation Market. Both PJM and the MMU have done extensive analysis of these changes in 2010 resulting in several technical improvements to the market solution software.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called cleared regulation. Assigned regulation is the total of self scheduled and cleared regulation.

Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market user interface. As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the Regulation Market clearing mechanism to provide regulation service for a given hour.

During 2011, the PJM Regulation Market total capability was 8,871 MW.[26] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2011, the average daily offer level, excluding units with offers which were made unavailable for the day, was 6,083 MW or 68.6 percent of total capability while the average hourly eligible offer level was 2,723 MW or 30.7 percent of total capability. In 2010, the average hourly eligible offer level was 32 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 9-5 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 9-5 PJM regulation capability, daily offer[27] and hourly eligible: Calendar year 2011

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	8,871	6,083	69%	2,723	31%
Off Peak	8,871			2,467	28%
On Peak	8,871			3,007	34%

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2011 was 3.00. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

26 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

27 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2011 State of the Market Report for PJM* as "required regulation."

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008, the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. In 2011, the PJM regulation requirement ranged from 514 MW to 1,565 MW. The average required regulation off-peak was 842 and the average required regulation on-peak was 1,017 MW (Table 9-6). In 2011, PJM scheduled a total of 7,867,278 MW of regulation compared to 9,037,733 MW in 2010.

Table 9-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: Calendar year 2011

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2011	925	3.00
Fall	866	2.74
Spring	785	2.91
Summer	1,115	2.81
Winter	930	3.16
Off Peak	842	3.01
On Peak	1,017	2.98

Market Concentration

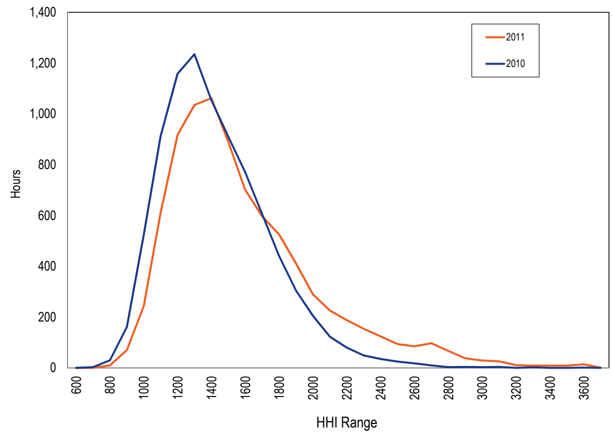
Hourly HHI values were calculated based on cleared regulation. Hourly HHIs ranged from a maximum of 4005 to a minimum of 818 in 2011 (compared to a range of 3675 to 763 in 2010), with a weighted average value of 1630, which is categorized as moderately concentrated by the FERC definitions. Table 9-7 summarizes the 2011 PJM Regulation Market HHIs. The minimum HHI, maximum HHI and the average HHI were all higher in 2011 than in 2010.

Table 9-7 PJM cleared regulation HHI: Calendar year 2011

Market Type	Minimum HHI	Weighted Average HHI	Maximum HHI
Cleared Regulation, 2011	818	1630	4005

In 2011, one percent of all periods had an HHI less than 1000 and 28 percent of all periods had an HHI greater than 1800, with a maximum HHI of 4005.[28] An HHI of 1800 is the threshold for "highly concentrated" by the FERC definitions. Figure 9-1 compares the 2011 HHI distribution with the 2010 HHI distribution.

Figure 9-1 PJM Regulation Market HHI distribution: Calendar years 2010 and 2011



The highest hourly market share in 2011 was 59 percent compared to the highest hourly market share in 2010 of 53 percent. 84 percent of all hours had a maximum market share greater than 20 percent in 2011 compared to 79 percent in 2010. The largest annual average hourly market share by a company was 22 percent. The top six annual average hourly market shares for cleared regulation in 2011 are listed in Table 9-8.

Table 9-8 Highest annual average hourly Regulation Market shares: Calendar year 2011

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	22
2	16
3	16
4	11
5	9
6	9

In 2011, 82 percent of hours failed the three pivotal supplier test. This means that for 82 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of

28 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

regulation was pivotal in 97 percent of pivotal hours. A second company was pivotal in 91 percent of the pivotal hours. A third company was pivotal in 89 percent of pivotal hours. Table 9-9 includes a monthly summary of three pivotal supplier results.

Table 9-9 Regulation market monthly three pivotal supplier results: Calendar year 2011

Month	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal
Jan	95%	88%
Feb	93%	87%
Mar	94%	89%
Apr	97%	92%
May	95%	87%
Jun	89%	80%
Jul	89%	81%
Aug	83%	71%
Sep	87%	74%
Oct	67%	59%
Nov	46%	41%
Dec	50%	45%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2011.

The MMU concludes from these results that the PJM Regulation Market in 2011 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, variable operating and maintenance (VOM) rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[29] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve. PJM then determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self scheduled to provide any of these services. Prior to clearing and assignment of regulation in a given hour, the Regulation Market is subject to market power screening via the TPS test.

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other

29 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In May 2009, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the opportunity cost calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

providers bilaterally, or self-schedule regulation to satisfy their obligation (Figure 9-2).[30] Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Total self scheduled regulation MW in 2011 was 18.9 percent of all regulation, which is an increase from 15.5 percent in 2010. The amount of self scheduled regulation was higher during off peak hours than during on peak hours while the amount of cleared regulation is higher during on peak hours than during off peak hours (Table 9-10). The higher ratio of self scheduled regulation is due in part to the participation of newly added battery units.

Figure 9-2 Off peak and on peak regulation levels: Calendar year 2011

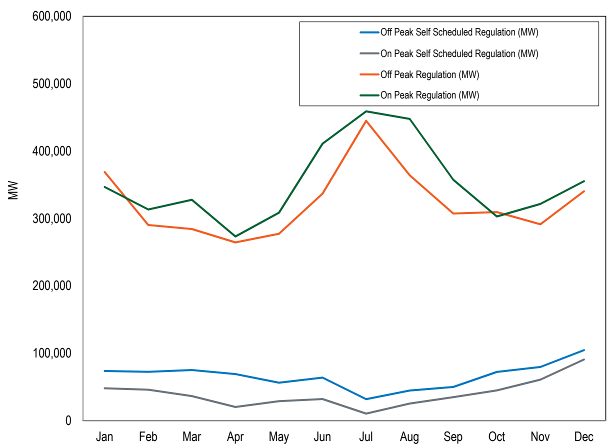


Table 9-10 Regulation sources: spot market, self scheduled, bilateral purchases: Calendar year 2011

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
Jan	576,029	116,421	16,670	709,121
Feb	462,394	114,568	17,553	594,515
Mar	463,708	107,791	28,109	599,608
Apr	418,890	86,402	18,273	523,565
May	469,104	81,357	15,978	566,439
Jun	586,661	89,878	15,127	691,666
Jul	756,218	38,791	15,647	810,656
Aug	721,498	67,841	14,442	803,781
Sep	565,935	81,239	15,063	662,237
Oct	479,328	113,824	15,062	608,213
Nov	457,665	137,603	16,315	611,582
Dec	475,935	190,778	19,182	685,895
Total	6,433,365	1,226,492	207,421	7,867,278

In November, 2011, demand resources (DSR) began participating in the Regulation Market.[31] DSR participation was approved in 2008, but several factors prevented DSR from qualifying. A rule preventing demand resources from being represented by more than one CSP kept some demand resources from participation if the resource was already represented by a CSP for any demand side product. In November, PJM members approved a rule change allowing a demand resource to be represented by more than one CSP. Another rule change was required to allow for equipment specific load data for regulation compliance instead of the previously required facility load data. A third rule was changed to allow regulation resources offering only 0.1 MW to participate. Previously PJM had required minimum offers of 0.5 MW for participation in the regulation market. Demand resources offered and cleared regulation for the first time in November 2011. Since they do not offer energy demand resources currently self schedule rather than offer competitively into the market.[32] These small amounts of regulation had virtually no impact on the regulation market in 2011.

Market Performance

Price

Figure 9-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price, based on the forecast LMP, multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP, multiplied by its assigned regulating capability.[33]

Regulation credits are awarded to generation owners that have either self scheduled or sold regulation into the market. Regulation credits for units self scheduled to provide regulation are equal to the clearing price times the unit's self scheduled regulating capability. Regulation credits for units that offer regulation into

30 See PJM "Manual 28: Operating Agreement Accounting," Revision 50, (January 1, 2012); para 4.2, pp 14-15.

31 See "DRS Proposed changes for DR in regulation market," MIC, <http://www.pjm.com/~/media/committees-groups/committees/mic/20111213/20111213-item-02a-proposed-changes-to-dr-in-regulation-market.ashx> (December 13, 2011).

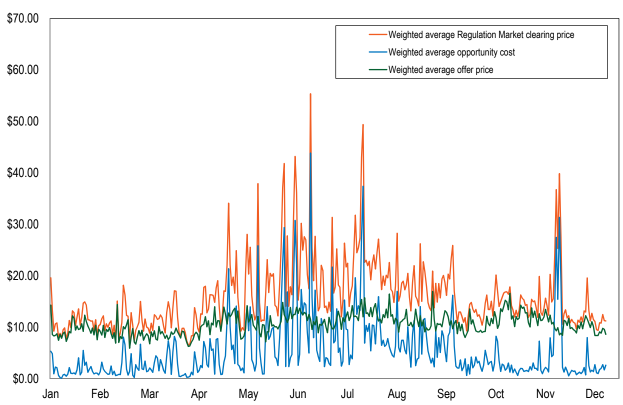
32 The reason for this is that SPREGO might otherwise optimally schedule them for energy which they could not provide. This is being studied and a solution is likely in 2012.

33 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 50, Section 4.2, "Regulation Credits" (January 1, 2012), p. 14. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

the market and are selected to provide regulation are the higher of the clearing price times the unit's assigned regulating capability, or the unit's regulation offer plus the unit's specific after the fact opportunity cost, times its assigned regulating capability. Although most units are paid the clearing price (RMCP) times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP and cost of the marginal unit. This means that a substantial portion of the total cost of regulation is determined by opportunity cost. As shown in Figure 9-3, about half of the regulation price is the opportunity cost of the marginal unit. Opportunity cost is a greater percentage of price when prices are high since offers tend to remain constant.

The weighted average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during 2011 was $10.57 per MWh, an increase from the weighted average offer in 2010 of $9.28. Although higher than in 2010, offers remain low compared to prior years as a result of the application of the three pivotal supplier test, which prevents noncompetitive offers from setting price. The weighted average opportunity cost of the marginal unit for the PJM Regulation Market in 2010 was $5.39. In the PJM Regulation Market the marginal unit opportunity cost averaged 34 percent of the RMCP. This is a reduction from the 2010 level of 47 percent.

Figure 9-3 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): Calendar year 2011

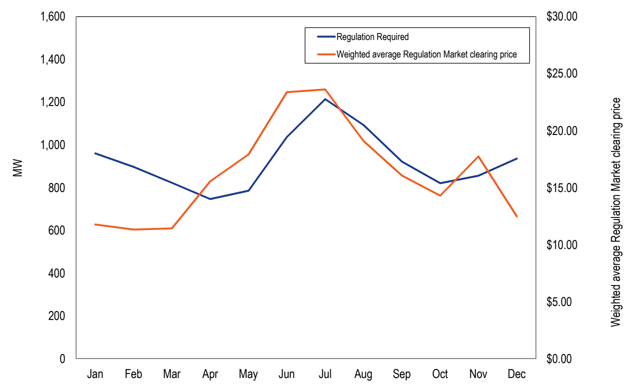


On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During the off-peak hours fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the opportunity cost portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements.

Figure 9-4 shows the level of demand for regulation by month in 2011 and the corresponding level of regulation price.

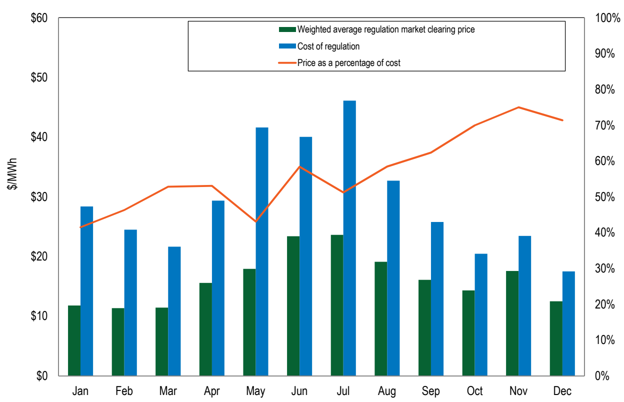
Figure 9-4 Monthly average regulation demand (required) vs. price: Calendar year 2011



The total cost of regulation per MW exceeds the price per MW because some regulation is procured out of the market, regulation MW actually delivered differs from regulation MW offered and cleared, or because there are adjustments to unit specific opportunity cost after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP, or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price to show the difference between the per MWh price of regulation and the per MWh total cost of regulation. The results in Figure 9-5 show that a significant portion of the costs of regulation are not incorporated in the Regulation Market clearing price. This discrepancy results in a lack of transparency in the Regulation Market.

PJM may call on resources not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. This often increases total regulation costs. If a resource is called on by PJM for the purpose of providing regulation, the resource is guaranteed recovery of regulation lost opportunity costs as well as start-up, no-load, and energy costs.

Figure 9-5 Monthly weighted, average regulation cost and price: Calendar year 2011



Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 9-11.

Table 9-12 provides a comparison of the weighted annual price and cost for PJM Regulation. For 2011, the weighted, average regulation price was $16.21 per MWh. The average regulation cost was $29.28 per MWh. The difference between the Regulation Market price and the actual cost of regulation was slightly greater in 2011 than it was in 2010. In 2011 the market price of regulation was only 55 percent of its actual cost. In 2010 the market price of regulation was 56 percent of its actual cost. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation and effectively pays a substantial proportion of Regulation Market revenues on an as bid basis rather than on the basis of the clearing price.

Regulation prices were ten percent lower in 2011 than in 2010 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.8 percent lower in 2011 than in 2010. The result was a small increase in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

A key source of the difference between the market clearing price and the cost per MW of regulation results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for regulation be determined after the close of the hour. All units cleared in the Regulation Market in the hour prior would be paid the market-clearing regulation price based on the actual LMP rather than the forecast LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would make the market price more reflective of the actual costs of providing the service.

Table 9-11 Total regulation charges: Calendar year 2011

Month	Scheduled Regulation (MWh)	Total Regulation Charges	Simple Average Regulation Market Clearing Price	Weighted Average Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.91	$11.77	$28.37
Feb	594,515	$14,551,995	$11.50	$11.33	$24.48
Mar	599,608	$12,967,924	$11.64	$11.42	$21.63
Apr	523,565	$15,361,871	$16.07	$15.56	$29.34
May	566,439	$23,561,565	$18.46	$17.92	$41.60
Jun	691,666	$27,696,820	$23.64	$23.38	$40.04
Jul	810,656	$37,375,988	$22.64	$23.61	$46.11
Aug	803,781	$26,271,979	$19.47	$19.10	$32.69
Sep	662,237	$17,074,805	$16.30	$16.07	$25.78
Oct	608,213	$12,437,431	$14.30	$14.30	$20.45
Nov	637,312	$14,929,690	$18.24	$17.57	$23.43
Dec	685,895	$11,993,503	$12.46	$12.48	$17.49

Table 9-12 Comparison of weighted price and cost for PJM Regulation, August 2005 through December 2011[34]

Year	Simple Average Regulation Market Price	Weighted Regulation Market Price	Regulation Market Cost	Regulation Price as Percentage of Cost
2005	$64.21	$64.03	$77.39	83%
2006	$31.13	$32.69	$44.98	73%
2007	$35.30	$36.86	$52.91	70%
2008	$41.78	$42.09	$64.43	65%
2009	$23.52	$23.56	$29.87	79%
2010	$17.96	$18.08	$32.07	56%
2011	$16.38	$16.21	$29.28	55%

New Developments in the Regulation Market Design

While the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics, CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC Order.[35] On October 20, 2011, FERC issued Order No. 755 directing PJM and other ISOs to redesign the regulation market to accommodate fast response resources.[36] The FERC directed PJM and other ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.[37] PJM is currently working with stakeholders to develop market rules that would results in an optimal, least cost combination of fast and traditional resources. This creates market design challenges, which if resolved, could improve the regulation market.

Regulation in PJM has traditionally been defined in terms of MW of capability that can be made available in five minutes and held (regulation up or down) for as long as an hour. Fast regulation resources, typified by batteries and flywheel technologies, are able to reach full capability much faster, but lack the ability to sustain a regulation up or down position for more than a few minutes. The current market design, built around the traditional resources, limited the ability of the new resource set to compete as a source of regulation.

To address the FERC requirements, PJM commissioned a study by KEMA designed to analyze the effectiveness of fast response regulation, in combination with traditional regulation resources, in meeting CPS1 requirements. The study evaluated the substitutability and synergies between fast response and traditional five-minute capability resources in meeting regulation compliance requirements. The results of the study indicated that the rate of substitution, and the overall effectiveness of fast response resources, was dependent upon system conditions and the amount of traditional resources simultaneously supplying regulation. The study indicated that a combination of fast and traditional resources could be more effective in providing for CPS1 compliance than using just traditional resources. PJM

34 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

35 See *2011 State of the Market Report for PJM*, "Appendix F."

36 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011).

37 *Id.*

is currently working with stakeholders to incorporate the results of this study into proposed modifications to the PJM regulation market. At present the plan is to implement changes in a series of phased steps, with Phase 1 expected in late Spring of 2012. It is expected that these changes will include a lower overall regulation requirement, a metric to evaluate the regulation delivered by all types of regulation resources, a process to measure and report regulation performance by resource type compared to the applicable fast (RegD) and slow (RegA) regulation signal, and the goal of reduced cost to acquire the level of required regulation.

Issues in the Regulation Market Design

The MMU has identified several significant issues with the design and implementation of the Regulation Market. These are broad statements of the issues and do not include an exhaustive list of all concerns. The issues address economic efficiency and competitiveness, and transparency.

- The definition of opportunity cost for units providing regulation is not correct. The result is a clearing price not reflective of the actual opportunity cost and therefore not efficient or competitive. The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market.
- PJM does not save some data elements that are necessary in order to replicate Regulation Market clearing prices. As a result, the opportunity cost used in the clearing price cannot be calculated and the clearing price cannot be calculated. While it may be possible to recreate data that is not saved, that is not the same as saving the data and making it available.
- It is not clear at what stages in the market clearing process the opportunity cost calculation includes shoulder hour opportunity costs. The documentation should be updated to clarify when shoulder hour opportunity costs are included in the market clearing process.
- The MMU analysis of the Regulation Market following the December 1, 2008, market rule changes resulted in the discovery that a significant number of marginal units whose schedule should have been switched to the lower of the price or cost based offer under the new rule were not switched. The MMU communicated this to PJM. PJM subsequently modified the market clearing process, effective September 9, 2010. The MMU has not been provided up an updated design document for these changes. It is not clear that PJM's approach is a complete fix but it is difficult to evaluate in the absence of documentation.

Table 9-13 Summary of changes to Regulation Market design

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

Analysis of Regulation Market Changes

There were significant changes made to the Regulation Market effective December 1, 2008. The rule changes are summarized in Table 9-13. The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[38] The MMU filed comments supporting the filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."[39]

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[40]

Introduction of TPS Testing

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests.

Increase Offer Margin from $7.50 to $12.00

The tariff modifications included an increase of the margin that may be added to cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs, more than 100 percent of the average cost of regulation. The MMU does not now recommend reducing the margin to the prior level of $7.50 per MW.

While there was no analytical support provided for the increased margin, it is simply a direct increase in payments. If an increase in payments for regulation is the goal, this is the best mechanism for implementing that goal as it is transparent and does not require inconsistent changes in market rules to increase revenues to the owners of regulation units.

Table 9-14 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh. The impact of the increased margin is calculated using the offer margin of all offering units, creating a new supply curve, and re-solving for the new marginal unit and new RMCP. The calculation assumes that synchronized reserve assignments and operating reserve allocations remain the same as in the existing solution. The increase in credits paid, of $10,954,411, is a result of the higher offer margin permitted under the new rules.

Change in the Definition of Opportunity Cost

The market clearing price of regulation is a sum of the regulation offer and the lost opportunity cost (LOC), including any applicable shoulder LOC, and in the case of off-line CTs a start-up cost. Offers in the Regulation Market consist of a cost based offer and, optionally, a price-based offer. The December 1, 2008, tariff modifications included a significant change in the definition of LOC. In the Regulation Market the direct offer price is made by the market participant and the opportunity cost is calculated by PJM based on forecast LMP for the next hour and added by PJM to the direct offer price to get the total offer price. The opportunity cost is, on average, approximately half the total offer price (Figure 9-3). Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market. The opportunity cost is also directly affected by the levels of LMP.

Under the prior rules, opportunity cost was defined as the difference between the LMP and the offer on which the unit was dispatched in the energy market. Under the December 1, 2008, tariff modifications, opportunity cost is defined as the difference between the LMP, and the lesser of the available price-based energy schedule or the most expensive available cost-based energy schedule. Thus, for units backing down to provide regulation, the new rules result in higher calculated opportunity costs.

The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in

38 See Filing initiating Docket No. ER09-13-000 (October 1, 2008).
39 *Id.* at 2.
40 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>.

Table 9-14 Impact of $12 adder to cost based regulation offer: December 2008 through December 2011

Year	Month	Weighted Regulation Market Clearing Price	Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	4%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	2%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	2%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	3%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	1%
2010	Apr	$17.26	$17.15	$13,246,951	$57,940	0%
2010	May	$19.16	$18.85	$19,286,137	$168,308	1%
2010	Jun	$19.46	$19.28	$23,333,299	$107,986	0%
2010	Jul	$23.39	$23.49	$34,017,900	($69,252)	-0%
2010	Aug	$21.50	$21.46	$28,928,214	$28,048	0%
2010	Sep	$19.30	$19.20	$19,592,362	$59,153	0%
2010	Oct	$13.57	$13.54	$10,613,185	$15,986	0%
2010	Nov	$11.69	$11.68	$11,930,514	$8,134	0%
2010	Dec	$14.04	$14.03	$25,225,775	$17,454	0%
2011	Jan	$11.77	$10.98	$20,116,696	$45,866	0%
2011	Feb	$11.33	$10.66	$14,551,986	$33,442	0%
2011	Mar	$11.42	$10.51	$12,967,915	$142,190	1%
2011	Apr	$15.56	$14.32	$15,361,860	$136,149	1%
2011	May	$17.92	$16.86	$23,561,554	$55,911	0%
2011	Jun	$23.38	$21.60	$27,696,810	$357,392	1%
2011	Jul	$23.61	$21.75	$37,375,975	$322,741	1%
2011	Aug	$19.10	$17.19	$26,271,969	$277,030	1%
2011	Sep	$16.07	$15.00	$17,074,790	$216,010	1%
2011	Oct	$14.30	$13.34	$12,437,411	$202,659	2%
2011	Nov	$17.57	$14.10	$14,929,802	$1,392,582	9%
2011	Dec	$12.48	$10.78	$11,924,355	$957,833	8%
Total				$728,601,484	$10,954,411	1.5%

the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years. The MMU recommends that this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient and consistent manner. The goal is also to ensure that regulation offers are taken in merit order based on their actual marginal costs, including their correctly calculated opportunity cost.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than the owner does.

A quantification of the financial impact of this rule is not possible because PJM does not save all of the data used to determine the final opportunity cost and market clearing price.[41]

In addition, the implementation of the December 1, 2008, changes was not done correctly. Had the revised opportunity cost rule been implemented correctly the MMU estimates that the schedule switching of marginal units in the Regulation Market would have occurred in 4,574 hours during the 37 month period of December 2008 through December 2011 of which 2,506, 59.0 percent, would have resulted in higher opportunity costs, and 1,958, 37.7 percent, would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 110 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

As actually implemented by PJM, schedule switching of marginal units occurred in 3070 hours, of which 2,115, 69 percent, had higher than correct opportunity costs and 712 hours, 23 percent, had lower than correct opportunity costs added to the marginal regulation offer. In the remaining 243 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

PJM made a change to the market software (SPREGO) effective September 9, 2010 to address the identified issue with schedule switching.[42]

PJM has begun design work on an MMU requested initiative to make the opportunity cost calculation consistent across all PJM markets. It is expected that this effort will be completed and installed in 2012. If implemented as recommended, this would resolve the opportunity cost issue in the Regulation Market.

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications eliminated the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from

41 The MMU has communicated this concern to PJM and been informed that steps are underway to make additional data available to the MMU.

42 See "Minutes," Market Implementation Committee, 11/09/2010, Agenda Item #9, pg. 5. <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx>.

those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the Regulation Market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserves in recent years and given the overall goal to reduce these non market payments. If there is actually a need for greater incentives, it should be established directly and the incentive payment made directly in the Regulation Market, for example through the offer margin.

Table 9-15 shows the additional revenue paid as a result of the rule change that no longer nets regulation revenue against balancing operating reserves. This rule change did not change the Regulation Market clearing price. The increase in total regulation credits paid, of $3,896,054, is a result of the elimination of the offset against operating reserve credits that result from the new rules.

Regulation Market Summary

The changes in market design increased the payments for regulation service. The impact on the Regulation Market that resulted from the December 1, 2008 rule eliminating the netting of credits against balancing operating reserves was $3,896,054. The impact on the Regulation Market of the December 2008 change increasing the allowable price offer markup from $7.50 to $12 was $10,954,411. These two rule changes increased regulation costs by $14,850,465 over the 37 month period from December 1, 2008 through December 31, 2011.

The dollar impact of changing the lost opportunity cost definition cannot be determined at this time primarily because the necessary data have not been saved by PJM. The rule would likely have changed the price in approximately 16.6 percent of hours between December 1, 2008, and December 31, 2011, (hours in which the marginal unit would have a schedule switch for the LOC calculation) and that in approximately 59 percent of those hours the marginal unit reduced output to regulate, meaning that the corresponding schedule switch would increase lost opportunity cost compared to the correct value. In 37 percent of the hours, the marginal unit increased output to regulate, meaning that the corresponding schedule switch would tend to reduce lost opportunity cost compared to the correct value.

The addition of the three pivotal supplier test to the Regulation Market improved the competitiveness of the Regulation Market results, compared to the prior market design, by eliminating the non-competitive behaviors that had existed in prior years. However, the other changes in the rules for the Regulation Market, in particular the change to the calculation of the opportunity cost, produced market results that were not competitive. The other changes in the rules resulted in prices in the Regulation Market that deviated from the competitive price that would have resulted without these changes.

Synchronized Reserve Market

Market Structure

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007: the RFC Synchronized Reserve Zone Market; and the Southern Synchronized Reserve Zone (Dominion) Market. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of Reliability*First* Corporation's imposed minimum requirement or the largest contingency on the system. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available to the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined by the Bedington – Black Oak interface as the RFC Synchronized Reserve Zone including all of AEP, BGE, DPL, JCPL, Met-Ed, PECO, Pepco, PPL, PSEG and parts of AP, AEP, and PENELEC. PJM no longer includes the interface definition in M-11 and reserves the right to modify this model to meet operational and reliability needs.[43] PJM must clear enough Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,300 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

Table 9-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2011

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1.0%
2009	Jan	$127,036	$26,614,105	0.5%
2009	Feb	$220,460	$20,972,293	1.1%
2009	Mar	$79,726	$17,618,413	0.5%
2009	Apr	$8,893	$12,171,811	0.1%
2009	May	$182,624	$21,166,797	0.9%
2009	Jun	$274,916	$24,566,721	1.1%
2009	Jul	$191,538	$20,065,104	1.0%
2009	Aug	$267,116	$23,010,216	1.2%
2009	Sep	$252,136	$15,216,790	1.7%
2009	Oct	$169,130	$12,882,665	1.3%
2009	Nov	$166,112	$10,695,843	1.6%
2009	Dec	$104,496	$17,303,919	0.6%
2010	Jan	$64,990	$29,465,392	0.2%
2010	Feb	$64,727	$16,640,892	0.4%
2010	Mar	$109,344	$14,156,600	0.8%
2010	Apr	$134,738	$13,246,951	1.0%
2010	May	$74,352	$19,286,137	0.4%
2010	Jun	$41,065	$23,333,299	0.2%
2010	Jul	$85,961	$31,927,050	0.3%
2010	Aug	$110,610	$28,928,214	0.4%
2010	Sep	$58,587	$19,592,362	0.3%
2010	Oct	$34,911	$10,613,185	0.3%
2010	Nov	$33,676	$11,930,514	0.3%
2010	Dec	$126,074	$25,225,775	0.5%
2011	Jan	$22,174	$20,116,704	0.1%
2011	Feb	$25,834	$14,551,995	0.2%
2011	Mar	$62,678	$12,967,924	0.5%
2011	Apr	$103,567	$15,361,871	0.7%
2011	May	$51,631	$23,500,428	0.2%
2011	Jun	$66,439	$27,696,810	0.2%
2011	Jul	$77,705	$37,375,975	0.2%
2011	Aug	$61,163	$27,426,669	0.2%
2011	Sep	$50,593	$17,050,086	0.3%
2011	Oct	$35,764	$9,542,173	0.4%
2011	Nov	$79,681	$11,030,193	0.7%
2011	Dec	$22,445	$20,271,120	0.1%
Total		$3,896,054	$729,131,461	0.5%

The Southern Synchronized Reserve Zone (Dominion) Market's reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or by load reductions.

All of the resources that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[44] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit. Sixty minutes prior to the start of the hour, self scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self scheduled Tier 2 resources, then a Tier 2 market is cleared at least 30 minutes prior to the start of the hour. The Tier 2 market clearing price is equivalent to the price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[45]

The Synchronized Reserve Market is characterized by structural market power. As a result, the synchronized reserve offer submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[46,47] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

In 2011 the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the administrative synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.[48] This is a six percent decrease from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in 2011 was 2.89 for the Mid-Atlantic Subzone. The ratio of offered and eligible synchronized reserve to the required Tier 2 was 3.00 for the RFC Zone for all hours in which a Tier 2 market was cleared. This is an 11 percent increase from 2010 when the ratio was 2.68. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 75.

45 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

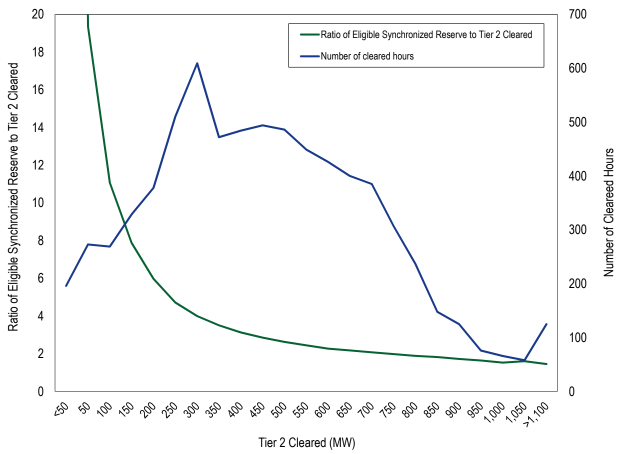
46 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 65.

47 See PJM. "Manual 15: Cost Development Guidelines," Revision 17 (June 1, 2011), p. 36.

48 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

reserve because there is usually a significant amount of Tier 1 synchronized reserve available. (See Figure 9-6.)

Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: Calendar year 2011



Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM to ensure system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis.[49]

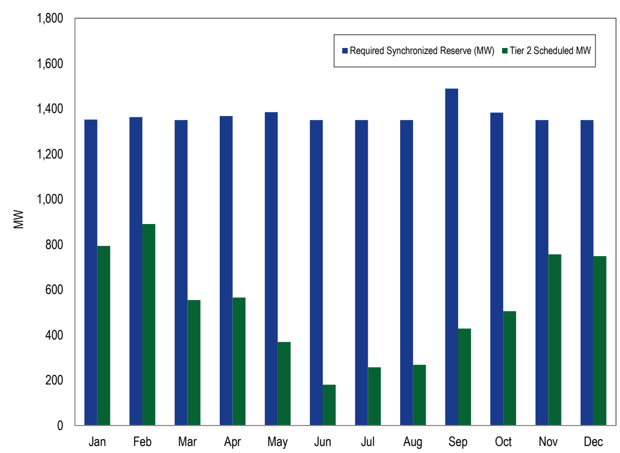
Currently the RFC synchronized reserve requirement is the greater of the ReliabilityFirst Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone was 1,350 MW for all of 2011. For the Mid-Atlantic Subzone the requirement was 1,300 MW for all of 2011 (Ref. Table 9-16).

Table 9-16 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through December 2011

Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
Dec 2008	May 2010	1,150	Dec 2008	Jan 2009	1,305
May 2010	Jul 2010	1,200	Jan 2009	Mar 2010	1,320
Jul 2010	Dec 2011	1,300	Mar 2010	Dec 2011	1,350

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred for several hours on February 9 and February 10, when the synchronized reserve requirement was set to 1,700 MW (RFC Zone only). Between April 19 and April 20 the requirement was 1,760 MW (Mid-Atlantic Subzone only). For May 5, the requirement was 1,760 MW. Between September 12 and September 26 it was set to 1,700 MW for most hours (RFC Zone only). Between October 26 and October 28 it was set to 1,700 MW for most hours. Figure 9-7 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2011 for the RFC Synchronized Reserve Market.

Figure 9-7 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2011



The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus

49 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The Synchronized Reserve Market solution is especially sensitive to this limit (known as transfer capacity). The higher this transfer capacity, the greater is the amount of Tier 1 synchronized reserve available in the East and so the less Tier 2 synchronized reserve that needs to be cleared to satisfy the synchronized reserve requirement. From 2007 through mid-March 2009, PJM market operations had estimated this transfer capacity at 70 percent of available RFC Tier 1 not exclusively in the Eastern subzone. However, PJM dispatch frequently observed a more restrictive limitation on transfer capacity in real-time operations on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover the requirement. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[50]

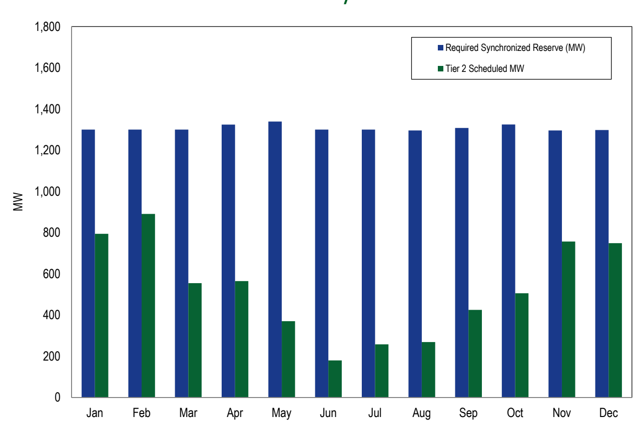
In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the Mid-Atlantic Subzone for the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This also reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market.[51] The transfer capacity was further reduced in late December, 2010, to 5 percent.

The integration of the Trans-Allegheny Line (TrAIL) project (performed in three stages April 8, May 13, and May 20, 2011) resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market. After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. Prior to the implementation of TrAIL the transfer capacity remained at 5 percent. After TrAil, the MMU observed several changes in the transfer capacity including 20 percent from April 20 through April 28; 10 percent from April 29 through May 19; 30 percent from May 20 through July 22; 5 percent from July 22 through August 1; 30 percent from August 1 through October 10; 50 percent from October 11 through November 14; and 15 percent from November 15 through December 31. The reasons for these changes are not clear and are not documented by PJM.

The MMU determined that these changes may be related to discrepancies between the amount of Tier 1 SPREGO estimates of MW available in the Mid-Atlantic Subzone and the amount actually available during the market hour. When the amount of Tier 1 actually available plus the amount of Tier 2 cleared is less than the required synchronized reserve (1,350 MW), then PJM dispatchers add additional synchronized reserve out of the market.

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2011, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than one percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price only for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 83 percent of all hours during 2011. A Tier 2 Synchronized Reserve Market was cleared in the Southern Synchronized Reserve Zone in less than one percent of hours (26 hours) during all of 2011. Figure 9-8 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 9-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2011



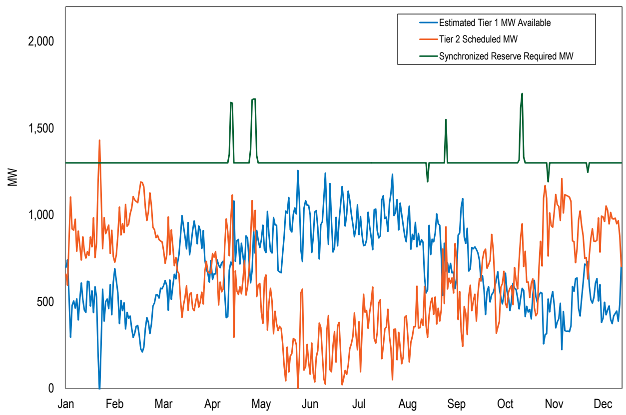
50 See *2007 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

51 See *2009 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets pp. 384, Table 6-14.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for 2011 was usually 1,300 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 1,760 MW on April 19 and 20, 2011. Throughout 2011, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,307 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

Figure 9-9 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased. The more Tier 1 is available the less Tier 2 is required.

Figure 9-9 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: Calendar year 2011



The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[52] The amount of 15 minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. The Southern Synchronized Reserve Zone cleared a Tier 2 market for only 26 hours in 2011.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was less concentrated in 2011 than it had been in 2010. Nevertheless the RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The participation of demand resources in the market continues to have a significant impact on the market solution, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the 2011 RFC cleared Synchronized Reserve Market was 2637, which is defined as "highly concentrated."

The largest hourly market share was 96 percent and 46 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 68 percent of all hours in 2010). In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2011, a single company had 60 percent or more of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 29 percent (compared to 43 percent in 2010). In other words, a single company sold 29 percent of synchronized reserves on average for all hours in which it had market share over the entire year (Table 9-17).

Table 9-17 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares[53]: Calendar year 2011

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	29%
2	25%
3	9%
4	8%
5	7%

In 2011, 63 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 100 percent of all pivotal hours, a second company was

52 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 66.

53 Note that the column "Cleared Synchronized Reserve Average Market Share" includes the average market share for the provider only in hours when that provider had a market share greater than zero. For this reason it is possible for the market shares of all providers to sum to greater than one hundred percent.

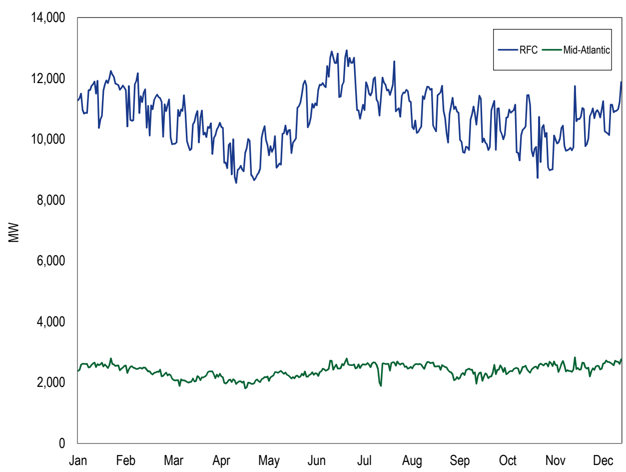
pivotal in 59 percent of all pivotal hours, and a third company was pivotal in 32 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

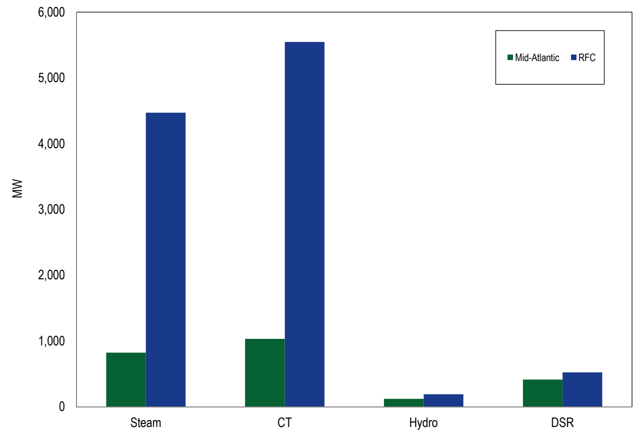
Figure 9-10 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 9-10 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2011



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-11 shows average offer MW volume by market and unit type.

Figure 9-11 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2011



The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2011. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 9-11. In 2011, DSR accounted for 29.3 percent of all cleared Tier 2 synchronized reserves. In 6.6 percent of hours when a synchronized reserve market was cleared all cleared MW was DSR (eight percent in 2010). In the hours when all supply was DSR, the simple average SRMCP was $1.28. The simple average SRMCP for all cleared hours was $9.48 (the simple average SRMCP in 2010 was $8.49). As defined by PJM, demand-side resources may at times be generation that is behind the meter.

Compliance

The MMU has reviewed synchronized reserve non-compliance between 2009 and 2011 and concluded that the incentive/penalty structure is not adequate. Although providers of Tier 2 synchronized reserve are paid for making synchronized reserve MW available every hour, it is only during spinning events that such Tier 2 synchronized reserve is actually used. The result is that it is possible to provide the service profitably with a very low level of compliance. This behavior does exist in this market. PJM's synchronized reserve penalty structure fails to penalize this behavior adequately. The MMU recommends that the Synchronized Reserve Market non-compliance penalties be restructured to address this issue and provide stronger incentives for compliance.

Synchronized reserve non-compliance has never caused a reliability problem at PJM.

DSR

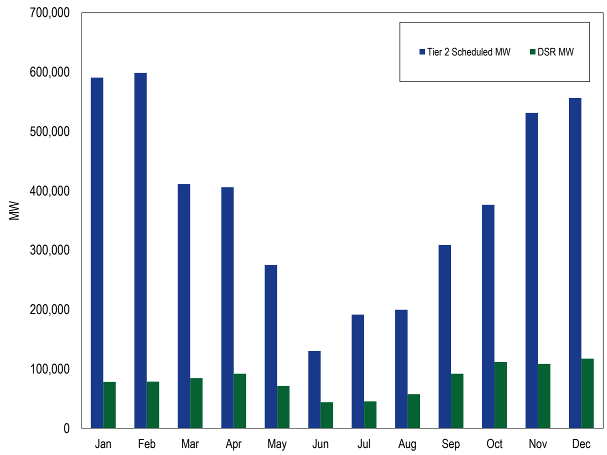
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 6.6 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 9-18), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 9-18 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2011

Month	Weighted average SRMCP	Weighted average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
Jan	$10.75	$0.10	0.0%
Feb	$10.91	NA	0.0%
Mar	$11.34	$2.04	2.0%
Apr	$16.07	$1.84	10.0%
May	$10.59	$1.71	14.0%
Jun	$13.41	$1.18	10.0%
Jul	$16.99	$0.62	6.0%
Aug	$10.62	$0.78	7.0%
Sep	$10.97	$1.73	15.0%
Oct	$9.65	$1.18	4.0%
Nov	$10.39	$0.71	3.0%
Dec	$10.04	$2.24	1.0%

Figure 9-12 shows total cleared plus self scheduled monthly synchronized reserve MW and cleared plus self scheduled MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong in 2011. Demand response remained significantly less expensive than other forms of synchronized reserve. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing. Furthermore demand resources add some diversity to the supply of synchronized reserve, reducing market concentration.

Figure 9-12 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2011



Market Performance

Price

Figure 9-13 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

Figure 9-13 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: Calendar year 2011

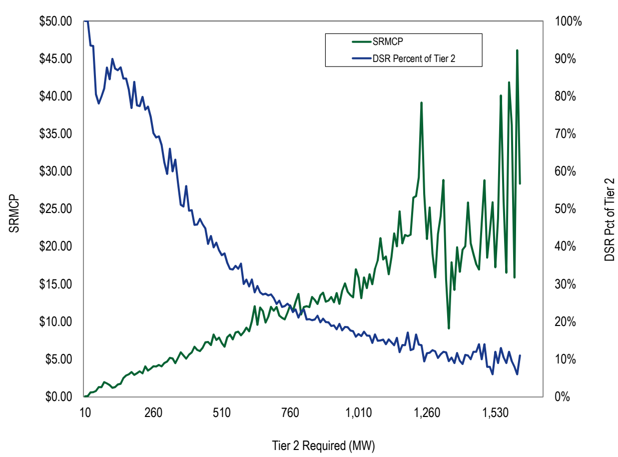


Figure 9-16 shows the weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific opportunity cost will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific opportunity cost, the result is that PJM's synchronized reserve cost per MW is higher than the SRMCP.

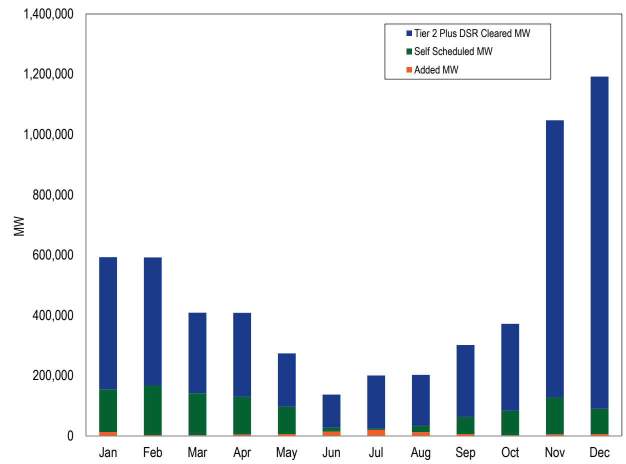
The weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2011 was $11.81 while the corresponding cost of synchronized reserve was $15.48.

The RFC Synchronized Reserve Market cleared as a single market in only 16 hours in all of 2011 with a weighted average $10.07 clearing price.

Price and Cost

A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. A low price to cost ratio is in part a result of out-of-market purchases of Tier 2 synchronized reserve by PJM dispatchers who need the reserves for reliability reasons. The primary reason for the relatively low price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP.

Figure 9-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: Calendar year 2011



Since the implementation of AC2 (November 7, 2011) PJM has seen an increase in the amount of Tier 2 synchronized reserve purchased. The green portion of Figure 9-14 is higher for the months of November and December, 2011 than in 2010. Although winter months typically require higher levels of Tier 2 synchronized reserve than Spring and Fall, the percentage increase in 2011 is much higher than it had been in 2010.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2011 is less than in 2010 (Figure 9-16). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2011, the cost of Tier 2 synchronized reserves was 31 percent higher than the weighted price. In 2010 this difference was 37 percent.

Figure 9-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2011

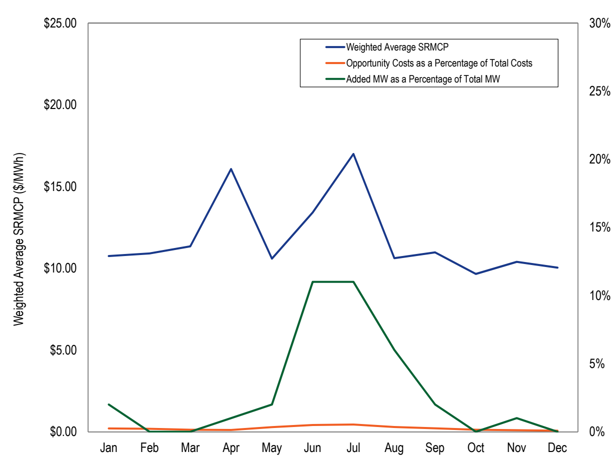
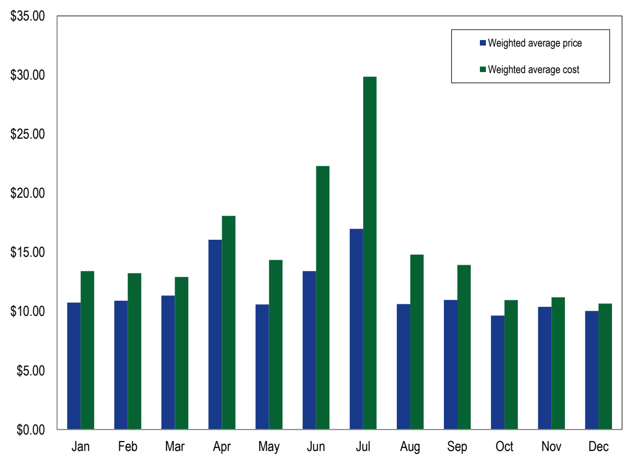


Figure 9-16 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): Calendar year 2011

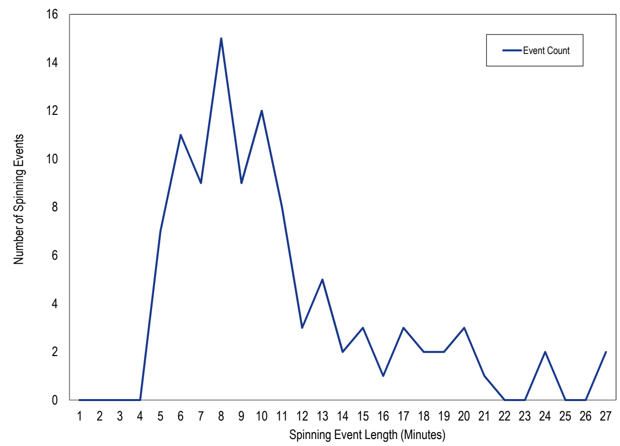


A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. Table 9-19 shows the price and cost history of the Synchronized Reserve Market since 2005. In March of 2009, PJM took steps to reduce the amount of aftermarket added synchronized reserve being added by the dispatchers. As a result, the price to cost ratio increased in 2009.

Synchronized reserve prices were 10.7 percent higher in 2011 than in 2010. Synchronized reserves total costs per MW were 6.9 percent higher in 2011 than in 2010. The total cost of synchronized reserves per MW was 31.1 percent higher than the market clearing price in 2011. The result was a decrease in the ratio of price to cost.

A key source of the difference between the market clearing price and the cost per MW of synchronized reserve results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for synchronized reserve be determined after the close of the hour. All units cleared in the synchronized reserve market in the hour prior would be paid the market-clearing price based on the actual LMP rather than the forecast LMP.

Figure 9-17 Spinning events duration distribution curve, January 2009 through December 2011



Spinning events (Table 9-20) are situations usually caused by a sudden generation outage or transmission disruption requiring PJM Dispatch to load primary synchronized reserve (spinning reserve).[54] The reserve remains loaded until system balance is recovered. From January 2009 through December 2011 PJM experienced 105 spinning events. This is almost 3 events per month. Spinning events generally last between 7 minutes and twenty minutes with an average length of eleven and a half minutes although several events have lasted longer than thirty minutes.

The need for synchronized (primary) reserve during spinning events is the reason for the Synchronized Reserve Market. Resources that offer and are scheduled in this market are obligated to provide their scheduled synchronized reserve whenever an event happens. When a scheduled resource fails to provide its full amount of synchronized reserve during a spinning event it is penalized.[55]

Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution at times, as a result of reliability concerns. The result is usually that total costs per MW (credits/MW) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

54 See PJM. "Manual 12, Balancing Operations," Revision 23 (November 16, 2011), pp. 34-35.
55 See PJM. "Manual 11, Energy & Ancillary Serves Market Operations" Revision 49 (January 1, 2012), 4.2.13, p.75.

Table 9-19 Comparison of weighted average price and cost for PJM Synchronized Reserve, 2005 through 2011

Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%

Table 9-20 Spinning Events, January 2009 through December 2011

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-17-2009 09:37	RFC	7	FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10
DEC-09-2009 22:34	Mid-Atlantic	34				DEC-15-2011 14:35	Mid-Atlantic	8
DEC-09-2009 22:37	RFCNonMA	31				DEC-21-2011 14:26	RFC	18
DEC-14-2009 11:11	Mid-Atlantic	8						

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution.

The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU also recommends that dispatchers document all actual unit deselections and the reasons for deselection.

Adequacy

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market, nor the Mid-Atlantic subzone of the RFC market experienced deficits in 2011.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[56]

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[57] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[58] In the ReliabilityFirst (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[59] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2011, the load forecast error component of this calculation was 1.87 percent of peak load forecast. This is a 0.03 percent decline from the load forecast error component of the 2010 DASR requirement. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2011, the forced outage component of the Day-Ahead Scheduling Reserve was 5.23 percent. This is a 0.25 percent increase from the 2010 forced outage component of the DASR requirement. For 2011 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 7.11 percent times Peak Load Forecast for RFC. This is a 0.23 percent decrease from the 2010 DASR requirement. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2011 VACAR scheduling reserve was set at 422 MW, an increase of 4 MW from the 2010 VACAR scheduling reserve requirement. The RFC and Dominion Day-Ahead Scheduling Reserve Requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day.

If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous with the Day-Ahead Energy Market.

Market Structure

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In 2011, the three pivotal supplier test was failed in the DASR Market in a total of 21 hours (less than one percent of all hours, a reduction from 1.3 percent of all hours in 2010).

56 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
57 See, 117 FERC ¶ 61,331 (2006).
58 PJM. "Manual 13, Emergency Requirements," Revision 47 (January 1, 2012), pp. 11-12.
59 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

Demand side resources do participate in the DASR Market, but remain insignificant. Demand side resources began to offer and clear the DASR market in November 2008. No demand side resources cleared the DASR market in 2011.

In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010.[60] As a result of increased DASR requirements, the DASR MW purchased increased by 7 percent in 2011 over 2010, from 53.2 MMW to 57.0 MMW.

Market Conduct

PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[61] Units that do not offer have their offers set to $0/MW.

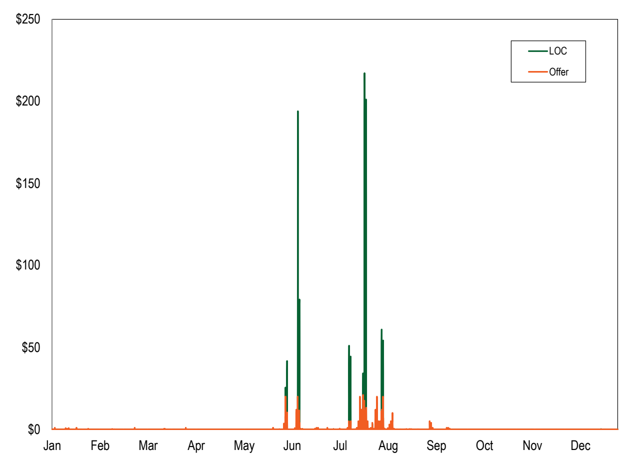
Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The marginal cost of providing DASR is zero. In the first five months of 2011, five percent of units offered at $50 or more and four percent offered at more than $900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. Between June 1, and December 31, 2011, thirteen percent of all units offered DASR at levels above $5, while less than one percent of units offered above $50. Two units offered above $900.

This behavior was limited to a relatively small number of units. Over the full year the impact on DASR prices of excessively high offers was minor as a result of a favorable balance between supply and demand. Of the 89 hours when the DASR clearing price was above $5.00, in 37 hours the price was set by a marginal unit with an offer price greater than $5.00. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.

Market Performance

For most (97 percent) of hours is 2011 DASR prices are determined entirely by the offer price of the marginal unit with units offering less than $0.03 marginal. Fifty six percent of hours in 2011 cleared at a price of $0.00. This means that most often DASR is available at no cost from the optimized energy solution. At prices above $0.05 however there is usually some re-dispatch required adding LOC to the clearing price. In 2011 there were 8.2 million unit-hours of cleared DASR (including clearing price of $0.00), of which only 5,140 unit-hours (0.06 percent) incurred an LOC. When energy prices get high however (as they did some hours in the summer) and there is less 30 minute reserve available from the energy dispatch, the price of DASR rises rapidly and LOC drives that price almost entirely. Although ninety five percent of hours cleared at $0.05 or less in 2011, the weighted average price of DASR was $0.55 per MW. In 2010, the weighted price of DASR was $0.16 per MW. The maximum clearing price in 2011 was $217.12 per MW on July 21. At prices above $0.05 however there is usually some re-dispatch required adding LOC to the clearing price (Figure 9-18).

Figure 9-18 Hourly components of DASR clearing price: Calendar year 2011



60 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

61 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 49 (January 1, 2012), p. 122.

Table 9-21 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: Calendar year 2011

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837
Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682
Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,885
Apr	5,265	$0.00	$0.05	$0.01	3,790,932	$24,463
May	5,554	$0.00	$25.52	$0.29	4,132,056	$894,607
Jun	7,305	$0.00	$193.97	$2.26	5,259,795	$9,653,815
Jul	8,647	$0.00	$217.12	$4.21	6,433,574	$22,880,723
Aug	7,787	$0.00	$61.91	$0.75	5,793,554	$3,577,433
Sep	6,535	$0.00	$5.00	$0.07	4,704,950	$292,252
Oct	5,874	$0.00	$0.04	$0.00	4,370,196	$3,655
Nov	6,067	$0.00	$0.04	$0.00	4,374,307	$6,155
Dec	6,532	$0.00	$0.21	$0.00	4,866,230	$6,181

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[62]

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid in their transmission zone following a possible blackout as well as to cover critical load. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan for its zone. PJM defines a minimum critical black start level for each transmission zone.[63] PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to an incentive rate or their revenue requirements (Table 9-22). The black start charges in Table 9-22 for the AEP zone include an estimated $6.5 million of charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[64]

Table 9-22 Black start yearly zonal charges for network transmission use: Calendar year 2011

ZONE	Network Charges	Black Start Rate ($/MW)
AECO	$485,333	$0.48
AEP	$7,058,952	$0.82
AP	$150,171	$0.05
ATSI	$193,376	$0.18
BGE	$2,143,162	$0.90
ComEd	$3,501,165	$0.47
DAY	$150,068	$0.13
DLCO	$35,936	$0.04
DPL	$438,623	$0.32
JCPL	$498,060	$0.23
Met-Ed	$487,132	$0.49
PECO	$1,045,053	$0.35
PENELEC	$283,555	$0.28
Pepco	$374,447	$0.17
PPL	$145,840	$0.06
PSEG	$3,100,807	$0.84

Formula Rates for Black Start Cost Recovery

Schedule 6A of the PJM OATT makes available formula rates for units identified as "critical" in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs).[65] Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of Schedule 6A was primarily to provide a level of compensation sufficient to encourage the owners of identified critical resources

62 OATT, Sheet No. 33.01.

63 See PJM. "Manual 36, System Restoration," Revision 15 (August 17, 2011) p. 49.

64 See the *2011 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserves."

65 The system restoration plan does not necessarily include all of the generating units in PJM capable of providing black start service, but it does include all units that receive payments for black start service from PJM.

to continue providing the service.[66] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

A series of proceedings at the FERC revealed that the cost recovery provisions of Schedule 6A were unsuited for units installing equipment necessary to provide black start service when no such capability previously existed.[67]

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying the cost of substantial capital investments in black start capable resources over a short period with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

The owners of black start service units had concerns that the provisions in Schedule 6A did not allow them to recover of the costs of new investment in equipment needed to comply with new Critical Infrastructure Protection Standards (CIPS) under development by the NERC.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to address these issues. Revisions to Schedule 6A developed by the BSSWG were filed with the FERC and approved by order issued May 29, 2009, the Commission approved the reforms.[68]

Some black start service unit owners claimed that they could not use the provisions of Schedule 6A allowing for the recovery of CIPS costs because they could not document non-CIPS related capital costs. The BSSWG developed a compromise proposed by the Market Monitor that allowed the incentive rate formula to be used as a proxy for cost for the first 100 MW for hydroelectric units and 50 MW for CTs and diesel units. By order issued January 13, 2012, the Commission approved the compromise, conditioned on PJM filing to correct certain provisions that allowed for possible double recovery of investment costs, consistent with a protest filed by the MMU.[69] The MMU has continuing concerns that the cost recovery provisions of Schedule 6A are unnecessarily complicated and may prove difficult to appropriately administer.

The MMU has significant concerns about the process for selecting and retaining the units that are included in the black start unit restoration plan. As revised, the formula under Schedule 6A allows black start service providers to recover the costs of new investment and reasonably conforms the terms of commitment by the providers of black start service to the period over which investment costs are recovered. However, the inclusion of CIPS costs applicable to black start service may lead to substantial increases in the cost of black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that could provide the same service at lower cost.

Black Start Service Procurement

There is no organized market for black start service in PJM and there is unlikely to be a competitive market for black start service as a result of the very local nature of the requirements.

PJM in conjunction with its transmission owners identifies locations where critical black start units are needed, considering each transmission zone separately, and conducts requests for proposals to procure service at those locations. PJM can accept proposals from

66 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").

67 In 2003, PJM, working with American Electric Power Service Corporation ("AEP"), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service unit. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation's offer to provide black start service from its Big Sandy Peaker Plant ("Big Sandy"). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC ("UPE") and Commonwealth Edison Company ("ComEd") that PJM grandfathered in the course of integrating ComEd's system into PJM. Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, although full investment cost recovery was accelerated to the first two years.

68 127 FERC ¶ 61,197 (2009).

69 138 FERC ¶ 61,020 (2012).

any party willing and able to provide the service at the required location, but the ability to compete at each location is limited. Separate planning for each transmission zone significantly constrains the definition of locations and reduces flexibility in considering how to restart the grid.[70] No customers or their representatives are involved in this process.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potentially cost-effective providers at the critical locations identified.

The principal obstacle is that PJM does not have the authority to develop a comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution for the entire system. The rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role. This is especially important to address situations where transmission owners have affiliates providing black start service in the PJM region. PJM should administer the plan on a regional basis.

Developing plans for each individual zone prevents or limits consideration of how resources in located in could be used in coordination with resources in a neighboring zone to achieve an efficient and orderly restoration. This approach artificially limits the resources and locations eligible to contribute to the restoration plan.

Although the procurement process is transparent and administered well, it is not a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by inelastic demand and substantial local market power.

Procurement of black start service necessarily involves a discussion of price. Currently, that discussion takes the form of a discussion between sellers and PJM, a neutral. The MMU is also a neutral in such discussions. Better balance in discussions about price is needed. An improvement would afford clear representation in the process to those responsible to pay for the service. Schedule 6A is designed to procure black start service as a service incremental to a unit's principal purpose of providing energy and capacity. In some cases, PJM has had to address units providing black start service that requires substantial investment in refurbishment. To date the approach has been to enter bilateral agreements that provide that the unit will recover the full investment needed to remain in service. These agreements provide for owners to retain the higher of cost-based recovery under Schedule 6A or capacity prices. This provision acknowledges that customers should at least receive the capacity value of the unit up to the cost support that they provide through Schedule 6A.

The risk remains that transmission customers in PJM may pay the cost of substantial capital investments in black start capable resources over a short period with no assurance that those resources will continue to provide black start service after the recovery period. Accordingly, the MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate how black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. This recommendation includes continued consideration of reforms to the procurement process and initiating a new effort to assign to PJM responsibility to develop a regional black start restoration plan.

The System Restoration Strategy Task Force (SRSTF) was formed by the MRC and will meet in 2012 to evaluate PJM's restoration plan, but it is not yet clear if the issue of least cost procurement for the entire PJM market will be addressed.

70 A restart is achieved by using smaller self starting units to start larger units, creating disparate energized areas that are gradually merged until the entire grid is energized. Vertically integrated utilities design their restoration plans around the facilities that they control or with which they are familiar. Now that PJM is the grid operator, the range of configurations that could start the system have increased and have the potential to be further and intentionally increased.

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at any bus is made up of three components: the system marginal price (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints.

The components of LMP are the basis for determining participant and location specific congestion and marginal losses. The Market Monitoring Unit (MMU) analyzed marginal losses and congestion in PJM markets for 2011.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

Overview

Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[2] The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation. Total network losses are determined by using a linearized approximation model based on the loss sensitivities to location-specific changes in power injection and withdrawal. Average losses are then calculated from total losses.

Total marginal loss costs equal net marginal loss costs plus explicit marginal loss costs plus net inadvertent loss costs. Net marginal loss costs equal load loss payments minus generation loss credits. Explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss costs are the losses associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour.[3] Unlike the other categories of marginal loss accounting, inadvertent loss costs are common costs not directly attributable to specific participants. Inadvertent related loss costs are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs. Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of Locational Marginal Price (LMP) while balancing marginal loss costs are based on deviations between day-ahead and real-time MWh priced at the marginal loss price component of Locational Marginal Price (LMP) in the Real-Time Energy Market.

2 For additional information, see OATT Section 3.4.
3 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

Marginal loss charges can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing marginal loss charges and credits are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Marginal loss credits are calculated as the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, plus the spot market energy value of the actual transmission loss MWh during that hour, plus residual net market adjustments in that hour.[4] Residual net market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

- **Total Marginal Loss Costs.** Total marginal loss charges decreased by $255.3 million or 15.6 percent, from $1,634.8 million in 2010 to $1,379.5 million in 2011. Day-ahead marginal loss costs decreased by $235.1 million or 14.1 percent, from $1,665.6 million in 2010 to $1,430.5 million in 2011. Balancing marginal loss costs decreased by $20.3 million or 65.9 percent from -$30.7 million in 2010 to -$51.0 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.

- **Monthly Marginal Loss Costs.** Fluctuations in monthly marginal loss costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns of generation and weather-induced changes in demand. Monthly marginal loss costs in 2011 ranged from $70.6 million in December to $213.7 million in July.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total net energy charges (total energy charges minus total energy credits) plus total net marginal loss charges (total marginal loss charges minus total marginal loss credits plus inadvertent and residual net market adjustments). Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments that is paid back in full to load and exports on a load ratio basis. The marginal loss

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

credits decreased by $250 million or 29.9 percent, from $836.7 million in 2010 to $586.7 million in 2011.

- **Zonal marginal loss costs.** In 2011, zonal marginal loss costs ranged from $3.2 million in RECO to $318.6 million in AEP. Compared to 2010, 2011 had a decrease in marginal loss costs across the PJM control zones, except PECO and DAY control zones. Total marginal loss costs in PJM in 2011 also changed due to the addition of the ATSI Control Zone, which accounted for $19.3 million or 1.4 percent of the total marginal loss costs.[5]

Congestion Cost

Total congestion costs equal net congestion costs plus explicit congestion costs plus net inadvertent congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion costs are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion costs are common costs not directly attributable to specific participants. Inadvertent related congestion costs are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[6] If an area is downstream from the constrained element, the area will experience positive congestion costs. If an area is upstream from the constrained element, the area will experience negative congestion costs.

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

- **Total Congestion.** Total congestion costs decreased by $425.4 million or 29.9 percent, from $1,423.6 million in 2010 to $998.2 million in 2011.[7] Day-ahead congestion costs decreased by $468.2 million or 27.3 percent, from $1,713.1 million in 2010 to $1,244.9 million in 2011. Balancing congestion costs increased by $42.8 million or 14.8 percent from -$289.5 million in 2010 to -$246.7 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns

5 See the *2011 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

6 The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load weighted PJM LMP.

7 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change.

of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2011 ranged from $35.0 million in May to $241.6 million in January.

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the 5004/5005 interface, the Belmont transformer, West Interface, and the AEP-Dominion interface. (Table 10-27)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2011.[8] Day-ahead congestion frequency increased by 45.8 percent from 106,253 congestion event hours in 2010 to 154,868 congestion event hours in 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces while congestion-event hours increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the MISO.

  Real-time congestion frequency decreased by 0.4 percent from 23,422 congestion event hours in 2010 to 22,468 congestion event hours in 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and transmission lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and MISO.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. The Day-Ahead market is consequently more-frequent constrained conditions compared to its corresponding Real-Time Market. During 2011, for only 5.6 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2011, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

  The AP South Interface was the largest contributor to congestion costs in 2011. With $238.9 million in total congestion costs, it accounted for 23.9 percent of the total PJM congestion costs in 2011. The top five constraints in terms of congestion costs together contributed $466.2 million, or 46.7 percent, of the total PJM congestion costs in 2011. The top five constraints were the AP South interface, the 5004/5005 interface, West interface, the Belmont transformer and the AEP – Dominion interface.

- **Zonal Congestion.**[9] Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in 2011.[10] ComEd had -$1,007.3 million in total load charges, -$1,277.3 million in total generation credits and -$30.9 million in explicit congestion, providing $239.0 million in total net congestion charges, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Electric Junction – Nelson transmission line, Crete – St. Johns flowgate (a reciprocally coordinated flowgate between PJM and MISO), AP South interface, East Frankfort – Crete transmission line and the Bunsonville – Eugene flowgate contributed $104.7 million, or 43.8 percent of the total ComEd Control Zone congestion costs.

  Similarly, the AEP Control Zone recorded the second highest congestion cost in PJM in 2011, with $195.1 million. The AP South interface contributed $33.1 million, or 17.0 percent of the total AEP Control Zone congestion cost in 2011. The AP Control Zone recorded the third highest congestion cost in PJM in 2011, with a cost of $143.9 million. The AP South interface contributed $63.9 million, or 44.4 percent of the total AP Control Zone congestion cost in 2011. The control zones in the Western (AEP, AP, ATSI, ComEd, DAY and DLCO) and Southern (Dominion) regions accounted for $737.2 million,

8 In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

9 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the *2011 State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses."

10 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012, the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

or 73.9 percent of congestion cost and the control zones in the Eastern region accounted for $261.0 million or 26.1 percent of congestion cost.

- **Ownership.** In 2011, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2011, financial companies received $108.2 million in net congestion credits, a decrease of $60.3 million or 35.8 percent compared to 2010. In 2011, physical companies paid $1,107.2 million in net congestion charges, a decrease of $484.9 million or 30.4 percent compared to 2010.

Conclusion

Marginal losses are incremental change in real system power losses caused by changes in system load and generation patterns. Total marginal loss costs decreased by $255.3 million or 15.6 percent, from $1,634.8 million in 2010 to $1,379.5 million in 2011. Marginal loss costs were significantly higher in the Day-Ahead Market than the Real-Time Market.

The net marginal loss bill is calculated by subtracting the generation loss credits from the sum of load loss charges, net explicit loss charges and net inadvertent loss charges. Since the net marginal bill is calculated on the basis of marginal, rather than average losses, there is an overcollection of marginal loss related costs. This overcollection, net of total energy charges and residual market adjustments[11], is the source of marginal loss credits. Marginal loss credits are fully distributed back to load and exports. Marginal loss credits were $586.7 million in 2011.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by $425.4 million or 29.9 percent, from $1,423.6 million in 2010 to $998.2 million in 2011. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 96.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2010 to 2011 planning period.[12] During the first seven months of the 2011 to 2012 planning period, total ARR and FTR revenues offset more than 100 percent of the congestion costs within PJM. FTRs were paid at 88.1 percent of the target allocation level for the 12-month period of the 2010 to 2011 planning period, and at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period.[13] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[14] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative

11 Residual net market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MWs.

12 See the 2011 *State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-36, "ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012.

13 See the *2011 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-22, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012"

14 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in 2011 were $998.2 million, which was comprised of load congestion payments of $112.2 million, negative generation credits of $1,009.9 million and negative explicit congestion of $123.8 million (Table 10-15).

Locational Marginal Price (LMP)

Components

As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

Locational Marginal Price (LMP) at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three basic components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[15] The first derivative of total losses with respect to the power flow equals marginal losses, which are twice the average losses for that power flow. The term congestion is related to physical limitations of elements of the transmission system to move power from point to point. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[16] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 10-1 shows the PJM real-time, load-weighted average LMP components for calendar years 2008 to 2011. The PJM price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). The components of the average PJM system price result from these different weights. The load-weighted average real-time LMP in 2011 decreased $2.41 or 5.0 percent from $48.35 in 2010 to $45.94 in 2011. The load-weighted average congestion component decreased $0.03 or 34.4 percent from $0.08 in 2010 to $0.05 in 2011. The load-weighted average loss component decreased $0.01 or

15 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses."

16 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

34.8 percent from $0.04 in 2010 to $0.02 in 2011. The load-weighted average energy component decreased $2.37 or 4.9 percent from $48.23 in 2010 to $45.87 in 2011. In terms of proportion of real-time LMP, the congestion and loss components both decreased, while the energy component became a greater proportion in 2011.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): Calendar years 2008 to 2011[17]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02

In the Real-Time Energy Market, the distributed load reference bus is weighted by system estimates of the load in real time. At the time the LMP is determined in the Real-Time Energy Market, the energy component equals the system load-weighted price. However, real-time bus-specific loads are adjusted, after the fact, according to updated information from meters. This meter adjusted load is accounting load that is used in settlements and forms the basis of the reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal, as reported here. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is due to the difference between estimated and meter corrected loads used to weight the load-weighted reference bus and the load-weighted LMP.

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for calendar years 2008 through 2011. The load-weighted average day-ahead LMP in 2011 decreased $2.46 or 5.2 percent from $47.65 in 2010 to $45.19 in 2011. The load-weighted average congestion component decreased $0.11 or 214.1 percent from $0.05 in 2010 to -$0.06 in 2011. The load-weighted average loss component decreased $0.08 or 124.3 percent from -$0.07 in 2010 to -$0.15 in 2011. The load-weighted average energy component decreased $2.27 or 4.8 percent from $47.67 in 2010 to $45.40 in 2011. In terms of proportion of day-ahead LMP, the congestion and loss components both decreased, while the energy component became a greater proportion in 2011.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): Calendar years 2008 to 2011

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)

In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed demand weighted price. The day-ahead weighted system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is due to the difference in the types of demand used to weight the load-weighted reference bus and the load-weighted LMP.

Zonal Components

The components of LMP were calculated for each PJM control zone. The components of LMP for the control zones are presented in Table 10-3 and Table 10-4 for calendar years 2010 and 2011.

Table 10-3 shows the real-time load-weighted average LMP components by zone and PJM for calendar years 2010 and 2011. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 10-4 shows the day-ahead load-weighted average LMP components by zone and PJM for calendar years 2010 and 2011.

17 The years 2006 and 2007 were removed from Table 2-20 and Table 2-24 because PJM did not begin to include marginal losses in economic dispatch and LMP models until June 1, 2007.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.03	$49.69	$3.87	$3.47	$57.81	$50.11	$4.95	$2.75
AEP	$40.35	$47.45	($4.67)	($2.43)	$42.97	$48.64	($3.99)	($1.68)
AP	$47.08	$47.42	($0.05)	($0.28)	$48.57	$48.99	($0.22)	($0.20)
ATSI	NA	NA	NA	NA	$46.88	$51.24	($3.85)	($0.51)
BGE	$59.19	$48.69	$8.04	$2.46	$58.74	$49.82	$6.62	$2.30
ComEd	$36.21	$47.95	($8.85)	($2.90)	$38.97	$49.12	($7.32)	($2.83)
DAY	$40.51	$48.10	($6.66)	($0.93)	$43.90	$49.40	($4.57)	($0.93)
DLCO	$39.41	$47.89	($6.68)	($1.79)	$43.30	$49.12	($4.15)	($1.67)
Dominion	$56.08	$48.86	$6.30	$0.92	$54.47	$49.83	$4.04	$0.60
DPL	$56.51	$49.07	$4.59	$2.85	$56.76	$49.95	$3.82	$2.99
JCPL	$56.00	$49.58	$3.92	$2.51	$58.09	$50.73	$4.62	$2.74
Met-Ed	$53.47	$48.20	$4.22	$1.05	$53.64	$49.22	$3.42	$1.00
PECO	$53.60	$48.36	$3.54	$1.70	$55.19	$49.47	$3.82	$1.90
PENELEC	$45.17	$47.19	($1.73)	($0.28)	$48.18	$48.27	($0.46)	$0.37
Pepco	$58.16	$48.70	$7.94	$1.51	$55.71	$49.82	$4.63	$1.26
PPL	$51.50	$47.90	$2.84	$0.76	$53.76	$48.95	$3.85	$0.96
PSEG	$55.78	$48.58	$4.73	$2.47	$57.16	$49.71	$4.78	$2.67
RECO	$54.85	$49.48	$3.20	$2.17	$53.17	$50.88	($0.15)	$2.44
PJM	$48.35	$48.23	$0.08	$0.04	$49.48	$49.40	$0.05	$0.03

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.03	$49.69	$3.87	$3.47	$57.45	$49.53	$4.67	$3.25
AEP	$40.35	$47.45	($4.67)	($2.43)	$42.90	$48.10	($3.25)	($1.96)
AP	$47.08	$47.42	($0.05)	($0.28)	$47.66	$47.96	($0.16)	($0.15)
ATSI	NA	NA	NA	NA	$46.14	$50.87	($3.07)	($1.66)
BGE	$58.37	$48.37	$6.80	$3.20	$57.10	$49.19	$5.16	$2.75
ComEd	$35.48	$47.12	($7.62)	($4.02)	$38.12	$48.12	($6.46)	($3.55)
DAY	$40.18	$47.71	($5.52)	($2.01)	$43.25	$48.64	($4.21)	($1.18)
DLCO	$40.03	$47.49	($5.26)	($2.20)	$42.60	$48.39	($4.13)	($1.67)
Dominion	$56.08	$48.48	$6.05	$1.54	$53.16	$49.11	$3.35	$0.70
DPL	$55.76	$48.66	$3.73	$3.37	$56.97	$49.29	$4.20	$3.48
JCPL	$55.07	$48.61	$3.13	$3.32	$56.24	$49.45	$3.73	$3.06
Met-Ed	$52.78	$47.72	$3.70	$1.35	$52.37	$48.08	$3.28	$1.01
PECO	$53.63	$47.94	$3.18	$2.51	$55.35	$48.61	$4.33	$2.41
PENELEC	$45.52	$46.41	($0.88)	($0.00)	$47.41	$47.72	($0.56)	$0.24
Pepco	$56.41	$47.24	$6.85	$2.32	$54.99	$48.72	$4.49	$1.79
PPL	$50.92	$47.45	$2.51	$0.95	$52.82	$48.27	$3.63	$0.93
PSEG	$54.99	$48.02	$3.47	$3.50	$56.24	$48.89	$4.27	$3.09
RECO	$55.56	$49.69	$2.67	$3.20	$53.55	$49.45	$1.75	$2.35
PJM	$47.65	$47.67	$0.05	($0.07)	$48.34	$48.55	($0.05)	($0.16)

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy charge is based on the applicable day-ahead and real-time energy component of LMP (SMP). Total energy charges are equal to the load energy payments minus generation energy credits, plus explicit energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Due to losses, total generation will be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across the every bus in every hour, the net energy bill is negative, with more generation credits than load charges in any given hour. This net energy bill is netted against total net marginal loss charges plus net residual market adjustments, which provides for full recovery of generation charges, with any remainder distributed back to load and exports as marginal loss credits.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.

- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.

- **Explicit Energy Charges.** Explicit energy charges are the net energy charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy charges will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.

- **Inadvertent Energy Charges.** Inadvertent energy charges are energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[18]

Total Calendar Year Energy Costs

Total charges decreased 2.1 percent from 6.5 percent in 2010 to 4.4 percent in 2011 of annual total PJM billings.[19] Table 10-5 shows type of charges by year for 2010 and 2011. Energy charges decreased by $3.7 million from $797.9 million in 2010 to $794.2 million in 2011.

Table 10-5 Total annual PJM charges by component (Dollars (Millions)): Calendar years 2010 and 2011[20]

	PJM Billing Charges (millions)					
	Energy Charges	Loss Charges	Congestion Charges	Total Charges	Total PJM Billing	Total Charges Percent of PJM Billing
2010	($798)	$1,635	$1,424	$2,261	$34,770	6.5%
2011	($794)	$1,380	$998	$1,583	$35,887	4.4%
Total	($1,592)	$3,014	$2,422	$3,844	$70,657	5.4%

Total energy charges are shown in Table 10-6 and Table 10-7. Table 10-6 shows the 2010 and 2011 PJM energy costs by category. Table 10-7 shows the 2010 and 2011 PJM energy costs by market category. The 2011 PJM total energy costs were comprised of $47,656.9 million in load energy payments, $48,478.9 million in generation energy credits, $0.0 million in explicit energy charges and $27.8 million in inadvertent energy charges.

18 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

19 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

20 The Energy Charges, Loss Charges and Congestion Charges include net inadvertent charges.

Table 10-6 Total annual PJM energy costs by category (Dollars (Millions)): Calendar years 2010 and 2011

	Energy Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	$53,101.4	$53,886.8	$0.0	($12.5)	($797.9)
2011	$47,656.9	$48,478.9	$0.0	$27.8	($794.2)

Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for 2011. The highest monthly energy cost was in July and totaled -$120.1 million or 15.1 percent of the total. The majority of the energy costs was in the Day-Ahead Energy Market and totaled -$735.1 million. The day-ahead costs were offset, in part, by a total of -$86.9 million in the balancing market.

Marginal Losses

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the MLMP at the location where the PJM member injects energy and the MLMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (MLMP), the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator

Table 10-7 Total annual PJM energy costs by market category (Dollars (Millions)): Calendar years 2010 and 2011

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	$53,164.8	$53,979.1	$0.0	($814.3)	($63.4)	($92.3)	$0.0	$28.9	($12.5)	($797.9)
2011	$48,142.3	$48,877.4	$0.0	($735.1)	($485.3)	($398.4)	$0.0	($86.9)	$27.8	($794.2)

Table 10-8 Monthly energy costs by type (Dollars (Millions)): Calendar year 2011

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$5,274.1	$5,364.4	$0.0	($90.3)	($51.6)	($46.4)	$0.0	($5.2)	$2.1	($93.3)
Feb	$3,465.4	$3,526.5	$0.0	($61.1)	($29.1)	($26.7)	$0.0	($2.4)	$2.3	($61.2)
Mar	$3,313.4	$3,365.7	$0.0	($52.4)	($31.0)	($25.6)	$0.0	($5.4)	$2.4	($55.3)
Apr	$3,073.2	$3,123.1	$0.0	($49.9)	($10.5)	($10.1)	$0.0	($0.4)	$2.5	($47.8)
May	$3,588.3	$3,643.0	$0.0	($54.8)	($0.7)	($0.5)	$0.0	($0.2)	$2.9	($52.1)
Jun	$4,968.7	$5,050.8	$0.0	($82.1)	($37.4)	($34.2)	$0.0	($3.2)	$1.2	($84.2)
Jul	$7,010.4	$7,120.4	$0.0	($110.0)	($87.7)	($71.0)	$0.0	($16.8)	$6.7	($120.1)
Aug	$4,713.0	$4,779.8	$0.0	($66.9)	($65.8)	($49.4)	$0.0	($16.4)	$4.9	($78.3)
Sep	$3,499.2	$3,554.2	$0.0	($55.0)	($78.6)	($73.2)	$0.0	($5.5)	$1.1	($59.4)
Oct	$3,110.0	$3,152.7	$0.0	($42.7)	($46.1)	($40.2)	$0.0	($5.9)	$0.3	($48.3)
Nov	$2,935.8	$2,966.0	$0.0	($30.2)	($12.8)	$1.8	$0.0	($14.6)	$0.8	($44.0)
Dec	$3,191.0	$3,230.6	$0.0	($39.6)	($34.1)	($23.0)	$0.0	($11.0)	$0.6	($50.1)
Total	$48,142.3	$48,877.4	$0.0	($735.1)	($485.3)	($398.4)	$0.0	($86.9)	$27.8	($794.2)

bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.

- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[21]

Marginal loss charges can be both positive and negative and consequently the load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Total Calendar Year Marginal Loss Costs

Loss charges decreased by 0.9 percent from 4.7 percent in 2010 to 3.8 percent in 2011 of annual total PJM billings.[22] Table 10-9 shows total marginal loss charges by year for 2010 and 2011. Loss charges decreased by $255.3 million from $1,634.8 million in 2010 to $1,379.5 million in 2011.

Table 10-9 Total annual PJM Marginal Loss Charges (Dollars (Millions)): Calendar years 2010 and 2011

	Loss Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2010	$1,635	NA	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
Total	$3,014		$70,658	4.3%

Total marginal loss costs for 2010 and 2011 are shown in Table 10-10 and Table 10-11. Table 10-10 shows the 2011 PJM marginal loss costs by category and Table 10-11 shows the 2011 PJM marginal loss costs by market category. The 2011 PJM total marginal loss costs were comprised of -$174.0 million in load loss payments, -$1,551.9 million in generation loss credits, $1.6 million in explicit loss costs and $12,775.2 in inadvertent loss charges.

Table 10-10 Total annual PJM marginal loss costs by category (Dollars (Millions)): Calendar years 2010 and 2011

	Marginal Loss Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5

21 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

22 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 10-11 Total annual PJM marginal loss costs by market category (Dollars (Millions)): Calendar years 2010 and 2011

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.7)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent charges	Grand Total
Jan	($16.6)	($192.8)	$12.3	$188.5	$5.3	$2.8	($5.4)	($2.9)	$0.0	$185.7
Feb	($9.9)	($124.8)	$6.8	$121.8	$3.3	$3.2	($1.9)	($1.8)	$0.0	$119.9
Mar	($10.5)	($112.5)	$6.8	$108.8	$2.0	$3.0	($3.8)	($4.8)	$0.0	$104.0
Apr	($10.3)	($91.6)	$3.4	$84.8	$1.7	$2.3	($5.1)	($5.6)	$0.0	$79.2
May	($8.6)	($93.9)	$9.0	$94.3	$3.3	$3.2	($7.1)	($7.0)	$0.0	$87.3
Jun	($34.4)	($158.4)	$5.9	$129.9	$4.2	$4.4	($4.3)	($4.5)	$0.0	$125.4
Jul	($40.0)	($254.3)	$3.1	$217.4	$8.4	$8.3	($3.8)	($3.7)	$0.0	$213.7
Aug	($25.3)	($162.1)	$1.2	$137.9	$2.0	$2.7	($2.7)	($3.5)	$0.0	$134.5
Sep	($18.6)	($123.1)	$3.1	$107.7	$5.4	$6.2	($3.9)	($4.7)	$0.0	$102.9
Oct	($9.8)	($93.5)	$2.0	$85.7	$1.7	$1.3	($4.1)	($3.6)	$0.0	$82.0
Nov	($15.9)	($93.5)	($1.6)	$76.0	$1.6	$0.5	($2.9)	($1.7)	$0.0	$74.3
Dec	($15.4)	($91.5)	$1.6	$77.8	$2.6	$2.4	($7.3)	($7.1)	$0.0	$70.6
Total	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for 2011. The highest monthly loss cost was in July and totaled $213.7 million or 15.5 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1,430.5 million. The day-ahead costs were offset, in part, by a total of -$51.0 million in the balancing market.

Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total net energy costs, the total net marginal loss costs and net residual market adjustments. The total energy costs are equal to the net energy costs (generation energy credits less load energy payments plus net inadvertent energy charges plus net explicit energy charges). Total marginal loss costs are equal to the net marginal loss costs (generation loss credits less load loss payments plus net inadvertent loss charges plus net explicit loss charges). Ignoring interchange, the existence of losses will cause total generation to be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across every generator and load bus in every hour, the net energy bill will be negative (ignoring net interchange), with more generation credits than load charges collected in any given hour. This net energy bill is netted against total net marginal loss charges and net residual market adjustments, with the remainder distributed back to load and exports as marginal loss credits. Residual market adjustments consist of the known day-ahead error value, day-ahead loss MW congestion value and balancing loss MW congestion value. The known day-ahead error value is the financial calculation for the MW imbalance created when the day-ahead case is solved. The day-ahead and balancing loss MW congestion values are congestion values associated with loss MW that need to be deducted from the net of the total marginal loss costs, total energy costs and day-ahead known error value before marginal loss credits can be distributed.

Table 10-13 shows the total net energy charges, the total net marginal loss charges collected, the net residual market adjustments[23] and total loss credits redistributed in calendar years 2010 and 2011. Marginal loss charges totaled $1,379.5 million, energy charges totaled -$794.2 million and net residual market adjustments totaled -$1.4 million in 2011. The marginal loss credits paid back to load plus exports in 2011 was $586.7 million, which is a decrease of $250 million or 29.9 percent compared to $836.7 million in 2010.

Table 10-13 Marginal loss credits (Dollars (Millions)): Calendar years 2010 and 2011

	Loss Credit Accounting (Millions)			
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2010	($797.9)	$1,634.8	$0.2	$836.7
2011	($794.2)	$1,379.5	($1.4)	$586.7

The reduction in marginal loss credits between 2010 and 2011 is due, at least in part, to an anomalous pricing event which occurred on October 10, 2011. On October 10, 2011, loss credits were negative in every hour. In the cases reviewed, the low LMP was related to the marginal losses component of LMP being unusually large relative to the energy component of LMP. The anomalous results were caused by incorrect loss penalty factors being utilized for all 24 hours on October 10.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[24] Total congestion charges are equal to the net congestion bill plus explicit congestion charges plus net inadvertent congestions charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 2011 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[25] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale

23 Based on currently available data, the MMU is not able to independently calculate residual market adjustments. The adjustments numbers included in the table are comprised of the sum of the known day-ahead error value, day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data. In sum, these elements reflect the difference between actual PJM loss credits and MMU calculations of loss credits based on available data.

24 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

25 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the deviations between the real-time and day-ahead transacted MWs and the differences between the real-time CLMP at the transactions' sources and sinks.
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[26]

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

26 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

Congestion costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[27]

Total Calendar Year Congestion

Congestion charges have ranged from 2.7 percent to 9.6 percent of annual total PJM billings since 2000.[28] Table 10-14 shows total congestion by year from 1999 through 2011. Congestion charges decreased by $425.4 million from $1,423.6 million in 2010 to $998.2 million in 2011.[29]

Table 10-14 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
1999	$65	NA	NA	NA
2000	$132	103.1%	$2,300	5.7%
2001	$271	105.3%	$3,400	8.0%
2002	$453	67.2%	$4,700	9.6%
2003	$464	2.4%	$6,900	6.7%
2004	$750	61.7%	$8,700	8.6%
2005	$2,092	178.8%	$22,630	9.2%
2006	$1,603	(23.4%)	$20,945	7.7%
2007	$1,846	15.1%	$30,556	6.0%
2008	$2,117	14.7%	$34,306	6.2%
2009	$719	(66.0%)	$26,550	2.7%
2010	$1,424	98.0%	$34,770	4.1%
2011	$998	(29.9%)	$35,887	2.8%
Total	$12,933	NA	$231,644	5.6%

27 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

28 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

29 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM*.

Table 10-15 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2010 to 2011

	Congestion Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2010	$251.2	($1,254.8)	($82.4)	$0.0	$1,423.6
2011	$112.2	($1,009.9)	($123.8)	$0.0	$998.2

Total congestion charges in Table 10-15 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO whose operating limits are respected by PJM.[30]

Table 10-16 shows the 2011 PJM congestion costs by category. The 2011 PJM total congestion costs were comprised of $112.2 million in load congestion payments, $1,009.9 million in negative generation congestion credits, and negative $123.8 million in explicit congestion costs.

Monthly Congestion

Table 10-17 shows that during calendar year 2011, monthly congestion charges ranged from a maximum of $241.6 million in January 2011 to a minimum of $35.0 million in May 2011. Table 10-18 shows the monthly congestion breakdown for calendar year 2010.

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In 2011, there were 154,868 day-ahead, congestion-event hours compared to 106,253 day-ahead, congestion-event

Table 10-16 Total annual PJM congestion costs by market category (Dollars (Millions)): Calendar years 2010 to 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2010	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	($0.0)	$1,423.6
2011	$36.2	($1,141.8)	$66.9	$1,244.9	$75.9	$131.9	($190.7)	($246.7)	$0.0	$998.2

Table 10-17 Monthly PJM congestion charges (Dollars (Millions)): Calendar year 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$27.0	($228.4)	$0.9	$256.4	$21.1	$15.6	($20.3)	($14.8)	$0.0	$241.6
Feb	$14.0	($77.5)	$1.0	$92.5	$5.6	$12.8	($10.9)	($18.0)	$0.0	$74.4
Mar	($2.5)	($58.8)	$2.2	$58.4	$0.2	$4.7	($10.0)	($14.6)	$0.0	$43.8
Apr	$5.0	($56.5)	$6.6	$68.0	$1.4	$6.4	($23.7)	($28.8)	$0.0	$39.2
May	$14.3	($41.5)	$8.6	$64.3	$3.0	$7.4	($24.9)	($29.3)	$0.0	$35.0
Jun	$1.8	($154.0)	$6.4	$162.3	$13.1	$22.4	($17.7)	($27.0)	$0.0	$135.2
Jul	$3.8	($184.1)	$6.5	$194.4	$21.2	$21.6	($20.2)	($20.6)	$0.0	$173.8
Aug	$4.7	($63.7)	$6.6	$75.0	($0.4)	$1.8	($9.7)	($11.9)	$0.0	$63.1
Sep	$0.0	($84.9)	$6.9	$91.9	$8.8	$21.2	($11.5)	($23.9)	$0.0	$67.9
Oct	($8.7)	($59.7)	$6.9	$58.0	$2.1	$6.2	($15.2)	($19.4)	$0.0	$38.6
Nov	($12.6)	($64.6)	$5.3	$57.3	($0.6)	$6.8	($11.9)	($19.2)	$0.0	$38.0
Dec	($10.6)	($68.1)	$9.0	$66.5	$0.5	$5.0	($14.6)	($19.1)	$0.0	$47.4
Total	$36.2	($1,141.8)	$66.9	$1,244.9	$75.9	$131.9	($190.7)	($246.7)	$0.0	$998.2

30 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreem ents/joa-complete.ashx > (Accessed March 13, 2012).

Table 10-18 Monthly PJM congestion charges (Dollars (Millions)): Calendar year 2010

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$37.8	($189.4)	$3.1	$230.2	$4.0	$3.1	($12.9)	($11.9)	($0.0)	$218.3
Feb	$25.5	($93.1)	$5.6	$124.2	($2.6)	$6.8	($8.3)	($17.7)	($0.0)	$106.4
Mar	$5.5	($27.8)	$4.2	$37.5	($2.6)	$6.6	($8.0)	($17.2)	($0.0)	$20.4
Apr	$6.1	($52.4)	$6.2	$64.7	($1.9)	$10.9	($9.3)	($22.1)	$0.0	$42.5
May	$35.0	($36.7)	$6.6	$78.2	$0.2	$1.1	($9.0)	($9.9)	($0.0)	$68.3
Jun	$62.6	($123.8)	$12.5	$199.0	$7.0	$1.3	($16.3)	($10.6)	($0.0)	$188.4
Jul	$39.1	($240.4)	$11.9	$291.4	$6.7	$11.3	($21.4)	($26.1)	($0.0)	$265.3
Aug	$23.9	($90.6)	$9.9	$124.4	$5.8	$10.8	($14.3)	($19.4)	($0.0)	$105.0
Sep	$7.3	($137.4)	$9.6	$154.4	$1.3	$16.6	($19.0)	($34.3)	($0.0)	$120.0
Oct	$0.8	($59.1)	$8.9	$68.8	($3.3)	$1.7	($13.5)	($18.6)	($0.0)	$50.2
Nov	($10.1)	($84.8)	$5.7	$80.3	($4.9)	$7.3	($16.5)	($28.6)	($0.0)	$51.7
Dec	$17.9	($229.3)	$12.8	$260.0	($9.8)	$32.5	($30.7)	($73.0)	$0.0	$187.1
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	($0.0)	$1,423.6

hours in 2010. In 2011, there were 22,468 real-time, congestion-event hours compared to 23,422 real-time, congestion-event hours in 2010.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. During 2011, for only 5.6 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2011, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

Congestion by Facility Type and Voltage

In 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transformers, while congestion frequency on interfaces and transmission lines decreased.[31]

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO and transformers in 2011 and decreased on PJM interfaces and transmission lines in 2011. Balancing congestion costs decreased on the reciprocally coordinated flowgates between PJM and MISO and transformers and increased on PJM interfaces and transmission lines in 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the 2011 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[32,33] For comparison, this information is presented in Table 10-20 for calendar year 2010.[34]

Total congestion costs associated with the reciprocally coordinated flowgates between PJM and the MISO increased by $2.5 million from $11.9 million in 2010 to $14.4 million in 2011.35 The flowgates day-ahead congestion cost and congestion event hours increased in 2011 compared to 2010. Flowgates balancing congestion costs decreased in 2011, while flowgates balancing congestion event hours increased in comparison to 2010. Balancing congestion costs on the reciprocally coordinated flow gates were generally negative in 2010 and 2011. The Crete – St Johns line flowgate accounted for $23.3 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2011. The largest contribution to negative congestion costs among flowgates came from the Oak

31 As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

32 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

33 The term *flowgate* refers to MISO flowgates in this context.

34 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

35 The congestion costs reported here for the reciprocally coordinated flowgates between PJM and the MISO flowgates are calculated in the same manner as all other internal PJM constraints and use the congestion accounting methods defined in this section. For the payments to and from the MISO based on the market-to-market settlement calculations, defined in the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.", see the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "PJM and Midwest ISO Joint Operating Agreement."

Grove - Galesburg flowgate with -$14.7 million in 2011 congestion costs.

Total congestion costs associated with interfaces decreased from $710.8 million in 2010 to $455.1 million in 2011. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 45.6 percent of total PJM congestion costs in 2011. Among interfaces, the AP South, the 5004/5005 and West interfaces accounted for the largest contribution to positive congestion costs in 2011. The AP South interface, with $238.9 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 23.9 percent of the total PJM congestion costs in 2011. The AP South, the 5004/5005 and West interfaces together accounted for $374.3 million or 82.2 percent of all interface congestion costs and were the largest contributors to positive congestion among interfaces in 2011.

Total congestion costs associated with transmission lines decreased 32.1 percent from $491.2 million in 2010 to $333.6 million in 2011. Transmission line congestion accounted for 33.4 percent of the total PJM congestion costs for 2011. The Electric Jct – Nelson, Dickerson – Quince Orchard and Graceton - Raphael Road lines together accounted for $61.4 million or 18.4 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2011.

Total congestion costs associated with transformers decreased 3.1 percent from $192.4 million in 2010 to $186.4 million in 2011. Congestion on transformers accounted for 18.7 percent of the total PJM congestion costs in 2011. The Belmont, Clover and Susquehanna transformers together accounted for $85.9 million or 46 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2011.

Table 10-21 and Table 10-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 10-21. In 2011, there were 154,868 congestion event hours in the Day-Ahead Market. Among those, only 8,623 (5.6 percent) were also constrained in the Real-Time Market. In 2010, among the 106,253 day-ahead congestion event hours, only 9,130 (8.6 percent) were binding in the Real-Time Market.

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during

Table 10-19 Congestion summary (By facility type): Calendar year 2011

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($110.1)	($215.5)	$12.0	$117.4	$8.4	$22.9	($88.5)	($103.0)	$14.4	23,982	7,385
Interface	$64.0	($395.3)	($10.7)	$448.7	$37.7	$38.3	$7.1	$6.4	$455.1	8,988	1,803
Line	$46.7	($343.6)	$38.4	$428.7	$23.2	$51.2	($67.1)	($95.1)	$333.6	88,573	9,252
Other	($0.5)	($4.7)	$0.6	$4.9	$2.2	$4.6	($0.4)	($2.8)	$2.0	1,227	248
Transformer	$35.1	($181.2)	$21.0	$237.3	$3.3	$14.5	($39.7)	($50.9)	$186.4	32,098	3,780
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	NA	NA
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	154,868	22,468

Table 10-20 Congestion summary (By facility type): Calendar year 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($59.3)	($125.8)	$5.5	$72.0	($0.8)	$6.0	($53.3)	($60.1)	$11.9	6,804	3,228
Interface	$163.1	($550.4)	$2.9	$716.3	$30.1	$31.4	($4.3)	($5.6)	$710.8	9,792	2,607
Line	$82.2	($528.3)	$68.9	$679.4	($22.6)	$64.1	($101.5)	($188.2)	$491.2	72,423	14,296
Other	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Transformer	$64.7	($149.8)	$13.5	$228.1	($6.8)	$8.5	($20.3)	($35.7)	$192.4	17,234	3,291
Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	NA	NA
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$1,423.6	106,253	23,422

which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In 2011, there were 22,468 congestion event hours in the Real-Time Market. Among these, 8,537 (38.0 percent) were also constrained in the Day-Ahead Market. In 2010, among the 23,422 real-time congestion event hours, only 8,936 (38.2 percent) were binding in the day-ahead.

Table 10-23 shows congestion costs by facility voltage class for 2011. In comparison to 2010 (shown in Table 10-24), congestion costs increased across 765 kV, 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 34 kV, 12 kV and unclassified facilities in 2011.

Congestion costs associated with 765 kV facilities increased from $5.9 million in 2010 to the $10.6 million experienced in 2011. Congestion on 765 kV facilities comprised 1.1 percent of total PJM congestion costs in 2011.

Congestion costs associated with 500 kV facilities decreased 30.8 percent from $876.5 million in 2010, to $544.0 million in 2011. Congestion on 500 kV facilities comprised 54.4 percent of total 2011 PJM congestion costs. The AP South, 5004/5005 and West interfaces accounted for $374.3 million or 68.8 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2011.

Table 10-21 Congestion Event Hours (Day-Ahead against Real Time): Calendar Years 2010 to 2011

	Congestion Event Hours					
	2011			2010		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	23,982	2,884	12.0%	6,804	973	14.3%
Interface	8,988	1,144	12.7%	9,792	1,728	17.6%
Line	88,573	2,945	3.3%	72,423	4,999	6.9%
Other	1,227	13	1.1%	0	0	0.0%
Transformer	32,098	1,637	5.1%	17,234	1,430	8.3%
Total	154,868	8,623	5.6%	106,253	9,130	8.6%

Table 10-22 Congestion Event Hours (Real Time against Day-Ahead): Calendar Years 2010 to 2011

	Congestion Event Hours					
	2011			2010		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	7,385	2,894	39.2%	3,228	993	30.8%
Interface	1,803	1,143	63.4%	2,607	1,727	66.2%
Line	9,252	2,884	31.2%	14,296	4,890	34.2%
Other	248	9	3.6%	0	0	0.0%
Transformer	3,780	1,607	42.5%	3,291	1,326	40.3%
Total	22,468	8,537	38.0%	23,422	8,936	38.2%

Table 10-23 Congestion summary (By facility voltage): Calendar year 2011

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.8	($9.3)	$2.3	$12.4	$2.9	$2.1	($2.6)	($1.8)	$10.6	1,098	183
500	$100.2	($465.4)	($5.5)	$560.1	$41.8	$46.0	($12.0)	($16.1)	$544.0	17,769	3,675
345	($98.0)	($264.2)	$15.7	$181.8	$10.3	$26.3	($69.4)	($85.5)	$96.3	29,924	4,535
230	$1.5	($176.9)	$12.6	$191.0	$18.9	$22.7	($36.2)	($40.0)	$151.0	23,742	3,554
161	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,736	1,138
138	$20.7	($173.7)	$26.0	$220.4	$4.4	$19.0	($46.1)	($60.7)	$159.7	59,561	7,686
115	$7.4	($27.8)	$4.2	$39.5	$1.1	$7.3	($1.5)	($7.7)	$31.8	12,161	1,109
69	$16.1	($1.1)	($0.1)	$17.1	($2.2)	$2.2	$0.1	($4.4)	$12.7	8,839	583
35	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	5
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	NA	NA
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0	154,868	22,468

Table 10-24 Congestion summary (By facility voltage): Calendar year 2010

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.0	($10.6)	$1.4	$12.9	($0.8)	$1.0	($5.2)	($7.0)	$5.9	540	261
500	$220.5	($673.1)	$16.0	$909.7	$27.9	$29.6	($31.5)	($33.2)	$876.5	17,232	5,803
345	($111.9)	($275.9)	$26.0	$190.1	($4.5)	$13.0	($84.3)	($101.8)	$88.3	13,919	3,845
230	$26.3	($173.7)	$23.8	$223.8	($5.5)	$28.6	($20.4)	($54.5)	$169.3	19,727	3,831
161	($0.3)	($0.6)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	114	242
138	$56.0	($214.5)	$21.9	$292.4	($8.7)	$30.6	($32.4)	($71.7)	$220.7	39,641	7,188
115	$41.1	($10.8)	$1.0	$52.9	($1.8)	$6.3	($2.0)	($10.1)	$42.8	7,597	1,589
69	$17.6	$4.7	$0.3	$13.3	($6.7)	$0.2	($0.5)	($7.4)	$5.9	7,091	644
35	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
34	$0.0	($0.1)	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.2	37	19
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	21	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
12	$0.3	$0.2	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	333	0
Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	NA	NA
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$1,423.6	106,253	23,422

Congestion costs associated with 345 kV facilities increased by 9.6 percent from $88.3 million in 2010, to $96.3 million in 2011. Congestion on 345 kV facilities comprised 9.6 percent of total 2011 PJM congestion costs. The Electrict Jct – Nelson line, the Crete – St. Johns Tap flowgate, and the East Frankfurt-Crete flowgate accounted for $65.4 million or 67.9 percent of all 345 kV congestion costs; they were the largest contributors to positive congestion among 345 kV facilities in 2011.

Congestion costs associated with 230 kV facilities decreased 10.8 percent from $169.3 million in 2010 to $151.0 million in 2011. Congestion on 230 kV facilities comprised 15.1 percent of total PJM congestion costs in 2011. The Clover transformer, Dickerson-Quince Orchard line and Susquehanna transformer accounted for $49.8 million or 33.0 percent of all 230 kV congestion costs and were the largest contributor to positive congestion among 230 kV facilities in 2011.

Congestion costs associated with 138 kV facilities decreased 27.6 percent from $220.7 million in 2010 to $159.7 million in 2011. Congestion on 138 kV facilities comprised 16.0 percent of total 2011 PJM congestion costs. The Brues-West Bellaire line and Busonville-Eugene flowgate together accounted for $20.9 million or 14.0 percent of all 138 kV congestion costs; they were the largest contributors to positive congestion among 138 kV facilities in 2011.

Congestion costs associated with 115 kV facilities decreased by 25.7 percent from $42.8 million in 2010, to $31.8 million in 2011. Congestion on 115 kV facilities comprised 3.2 percent of total 2011 PJM congestion costs. The Cly – Collins line and Glenarm-Windy Edge line together accounted for $8.7 million or 27.4 percent of all 115 kV congestion costs; they were the largest contributors to positive congestion among 115 kV facilities in 2011.

Congestion costs associated with 69 kV and below facilities increased by 115.3 percent from $5.9 million in 2011, to $12.7 million in 2011. Congestion on 69 kV comprised 1.3 percent of total 2011 PJM congestion costs. The Cromby transformer and Carnagie – Tidd line and accounted for $8.8 million in congestion costs. They had the largest contribution to congestion costs among 69 kV and below facilities.

Constraint Duration

Table 10-25 lists calendar year 2010 and 2011 constraints that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from 2010 to 2011.

The South Mahwah – Waldwick line, AP South interface and Belmont Transformer were the most frequently occurring constraints in 2011. The South Mahwah – Waldwick line saw the largest increase in congestion-event hours from 2010. The Waterman – West Dekalb line saw the largest decrease in congestion-event hours from 2010 to 2011.

Table 10-25 Top 25 constraints with frequent occurrence: Calendar years 2010 to 2011

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	5,269	5,269	8	494	486	0%	60%	60%	0%	6%	6%
2	AP South	Interface	4,622	4,111	(511)	1,516	1,013	(503)	53%	47%	(6%)	17%	12%	(6%)
3	Belmont	Transformer	1,872	4,367	2,495	203	497	294	21%	50%	28%	2%	6%	3%
4	Danville - East Danville	Line	647	4,608	3,961	0	0	0	7%	53%	45%	0%	0%	0%
5	Crete - St Johns Tap	Flowgate	2,051	3,354	1,303	810	1,115	305	23%	38%	15%	9%	13%	3%
6	Michigan City - Laporte	Flowgate	50	2,935	2,885	67	632	565	1%	34%	33%	1%	7%	6%
7	Electric Jct - Nelson	Line	1,495	2,926	1,431	258	158	(100)	17%	33%	16%	3%	2%	(1%)
8	Emilie - Falls	Line	81	2,920	2,839	24	11	(13)	1%	33%	32%	0%	0%	(0%)
9	Oak Grove - Galesburg	Flowgate	114	1,736	1,622	242	1,131	889	1%	20%	19%	3%	13%	10%
10	Wolfcreek	Transformer	220	2,547	2,327	8	226	218	3%	29%	27%	0%	3%	2%
11	Cox's Corner - Marlton	Line	16	2,625	2,609	0	0	0	0%	30%	30%	0%	0%	0%
12	Conesville	Transformer	0	2,610	2,610	0	0	0	0%	30%	30%	0%	0%	0%
13	Linden - VFT	Line	173	2,602	2,429	0	0	0	2%	30%	28%	0%	0%	0%
14	Bunsonville - Eugene	Flowgate	31	2,444	2,413	0	11	11	0%	28%	28%	0%	0%	0%
15	Pinehill - Stratford	Line	1,506	2,352	846	0	0	0	17%	27%	10%	0%	0%	0%
16	Brues - West Bellaire	Line	0	1,718	1,718	78	598	520	0%	20%	20%	1%	7%	6%
17	Fairview	Transformer	536	2,288	1,752	0	0	0	6%	26%	20%	0%	0%	0%
18	Wylie Ridge	Transformer	945	1,910	965	656	357	(299)	11%	22%	11%	7%	4%	(3%)
19	AEP-DOM	Interface	691	1,786	1,095	187	185	(2)	8%	20%	13%	2%	2%	(0%)
20	East Frankfort - Crete	Line	3,084	1,546	(1,538)	850	329	(521)	35%	18%	(18%)	10%	4%	(6%)
21	Cumberland - Bush	Flowgate	0	1,599	1,599	22	215	193	0%	18%	18%	0%	2%	2%
22	Conesville Prep - Conesville	Line	187	1,782	1,595	0	0	0	2%	20%	18%	0%	0%	0%
23	Redoak - Sayreville	Line	898	1,752	854	57	11	(46)	10%	20%	10%	1%	0%	(1%)
24	Waukegan - Zion	Line	95	1,734	1,639	0	7	7	1%	20%	19%	0%	0%	0%
25	Clover	Transformer	514	1,238	724	259	469	210	6%	14%	8%	3%	5%	2%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2010 to 2011

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	5,269	5,269	8	494	486	0%	60%	60%	0%	6%	6%
2	Danville - East Danville	Line	647	4,608	3,961	0	0	0	7%	53%	45%	0%	0%	0%
3	Michigan City - Laporte	Flowgate	50	2,935	2,885	67	632	565	1%	34%	33%	1%	7%	6%
4	Waterman - West Dekalb	Line	3,003	2	(3,001)	343	0	(343)	34%	0%	(34%)	4%	0%	(4%)
5	Emilie - Falls	Line	81	2,920	2,839	24	11	(13)	1%	33%	32%	0%	0%	(0%)
6	Belmont	Transformer	1,872	4,367	2,495	203	497	294	21%	50%	28%	2%	6%	3%
7	Conesville	Transformer	0	2,610	2,610	0	0	0	0%	30%	30%	0%	0%	0%
8	Cox's Corner - Marlton	Line	16	2,625	2,609	0	0	0	0%	30%	30%	0%	0%	0%
9	Wolfcreek	Transformer	220	2,547	2,327	8	226	218	3%	29%	27%	0%	3%	2%
10	Oak Grove - Galesburg	Flowgate	114	1,736	1,622	242	1,131	889	1%	20%	19%	3%	13%	10%
11	Linden - VFT	Line	173	2,602	2,429	0	0	0	2%	30%	28%	0%	0%	0%
12	Bunsonville - Eugene	Flowgate	31	2,444	2,413	0	11	11	0%	28%	28%	0%	0%	0%
13	Athenia - Saddlebrook	Line	3,317	1,398	(1,919)	364	4	(360)	38%	16%	(22%)	4%	0%	(4%)
14	Brues - West Bellaire	Line	0	1,718	1,718	78	598	520	0%	20%	20%	1%	7%	6%
15	Tiltonsville - Windsor	Line	2,723	1,004	(1,719)	506	72	(434)	31%	11%	(20%)	6%	1%	(5%)
16	East Frankfort - Crete	Line	3,084	1,546	(1,538)	850	329	(521)	35%	18%	(18%)	10%	4%	(6%)
17	Bedington - Black Oak	Interface	2,283	679	(1,604)	212	7	(205)	26%	8%	(18%)	2%	0%	(2%)
18	Cumberland - Bush	Flowgate	0	1,599	1,599	22	215	193	0%	18%	18%	0%	2%	2%
19	Doubs	Transformer	1,363	59	(1,304)	500	51	(449)	16%	1%	(15%)	6%	1%	(5%)
20	Fairview	Transformer	536	2,288	1,752	0	0	0	6%	26%	20%	0%	0%	0%
21	Waukegan - Zion	Line	95	1,734	1,639	0	7	7	1%	20%	19%	0%	0%	0%
22	Crete - St Johns Tap	Flowgate	2,051	3,354	1,303	810	1,115	305	23%	38%	15%	9%	13%	3%
23	Conesville Prep - Conesville	Line	187	1,782	1,595	0	0	0	2%	20%	18%	0%	0%	0%
24	Pleasant Valley - Belvidere	Line	2,529	1,093	(1,436)	467	315	(152)	29%	12%	(16%)	5%	4%	(2%)
25	Marquis - Dept of Energy	Line	6	1,498	1,492	0	0	0	0%	17%	17%	0%	0%	0%

Table 10-27 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2011

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011
1	AP South	Interface	500	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	24%
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	8%
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	6%
4	Belmont	Transformer	AP	$7.7	($49.9)	($2.2)	$55.5	($3.5)	($3.2)	($1.6)	($1.8)	$53.7	5%
5	AEP-DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	4%
6	Electric Jct - Nelson	Line	ComEd	($10.8)	($44.4)	$7.7	$41.3	$0.4	$3.7	($7.7)	($11.0)	$30.3	3%
7	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	2%
8	Crete - St Johns Tap	Flowgate	MISO	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	2%
9	Clover	Transformer	Dominion	$0.4	($21.4)	$4.6	$26.4	$2.8	$3.4	($7.8)	($8.5)	$17.9	2%
10	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	2%
11	Dickerson - Quince Orchard	Line	Pepco	($9.4)	($28.8)	($1.7)	$17.7	$4.6	$7.4	$2.7	($0.2)	$17.5	2%
12	Oak Grove - Galesburg	Flowgate	MISO	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	(1%)
13	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	1%
14	Graceton - Raphael Road	Line	BGE	$10.9	($1.1)	($0.8)	$11.2	$0.7	($1.1)	$0.5	$2.4	$13.5	1%
15	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.6	$2.2	$1.2	($2.5)	($1.5)	$12.1	1%
16	East Frankfort - Crete	Line	ComEd	($10.0)	($23.7)	($1.3)	$12.4	$0.6	$0.6	($0.6)	($0.6)	$11.8	1%
17	Brues - West Bellaire	Line	AEP	$19.8	$4.5	$0.7	$16.1	($2.1)	$1.8	($1.5)	($5.4)	$10.7	1%
18	Breed - Wheatland	Line	AEP	($4.8)	($13.2)	$2.0	$10.5	$0.0	($0.0)	($0.1)	($0.0)	$10.4	1%
19	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($9.9)	(1%)
20	Plymouth Meeting - Whitpain	Line	PECO	($0.9)	($10.8)	($0.0)	$9.9	$0.2	$0.2	($0.1)	($0.2)	$9.7	1%
21	Cloverdale	Transformer	AEP	$0.5	($7.6)	$1.6	$9.7	$0.7	$0.6	($0.1)	($0.0)	$9.7	1%
22	Bunsonville - Eugene	Flowgate	MISO	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	1%
23	Unclassified	Unclassified	Unclassified	$1.1	($1.5)	$5.4	$8.0	$1.2	$0.3	($1.4)	($0.5)	$7.5	1%
24	Pleasant Valley - Belvidere	Line	ComEd	($6.6)	($17.6)	$1.7	$12.7	($0.6)	$2.1	($3.0)	($5.7)	$7.0	1%
25	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	1%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for calendar years 2011 and 2010. The AP South interface was the largest contributor to congestion costs in 2011. With $238.9 million in total congestion costs, it accounted for 23.9 percent of the total PJM congestion costs in 2011. The top five constraints in terms of congestion costs together comprised 46.7 percent of the total PJM congestion costs in 2011.

Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[36] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[37] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM took dispatch action to control during 2011 and 2010, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2011, the Crete – St Johns Tap flowgate made the most significant contribution to positive congestion while the Oak Grove – Galesburg flowgate made the most significant contribution to negative congestion.

36 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

37 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009), Section 2.2.24 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012) .

Table 10-28 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2010

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010
1	AP South	Interface	500	$128.3	($292.9)	($2.3)	$419.0	$15.5	$15.7	$1.5	$1.3	$420.2	30%
2	Bedington - Black Oak	Interface	500	$44.6	($60.3)	$2.7	$107.7	$0.7	$1.9	($1.6)	($2.9)	$104.8	7%
3	5004/5005 Interface	Interface	500	($14.6)	($106.4)	$0.0	$91.8	$12.3	$10.8	($1.3)	$0.1	$92.0	6%
4	Doubs	Transformer	AP	$9.6	($57.8)	$0.7	$68.1	$3.1	$4.1	($2.8)	($3.8)	$64.4	5%
5	AEP-DOM	Interface	500	$10.2	($53.0)	$2.5	$65.8	$0.5	$1.2	($2.8)	($3.5)	$62.3	4%
6	East Frankfort - Crete	Line	ComEd	($22.0)	($67.5)	$6.1	$51.6	($3.9)	$0.2	($7.6)	($11.7)	$39.8	3%
7	Crete - St Johns Tap	Flowgate	MISO	($46.0)	($88.6)	($5.1)	$37.4	$1.4	$0.2	($9.0)	($7.8)	$29.6	2%
8	Cloverdale - Lexington	Line	500	$19.6	($11.2)	$3.0	$33.7	($2.5)	($3.4)	($5.5)	($4.7)	$29.1	2%
9	Belmont	Transformer	AP	$4.1	($26.8)	($0.6)	$30.2	($6.8)	($3.6)	($0.3)	($3.6)	$26.6	2%
10	Brandon Shores - Riverside	Line	BGE	($15.5)	($42.4)	($0.4)	$26.5	$0.2	$1.7	$0.4	($1.1)	$25.4	2%
11	Mount Storm - Pruntytown	Line	500	$11.8	($10.4)	$2.1	$24.3	$2.0	($2.9)	($4.8)	$0.1	$24.4	2%
12	West	Interface	500	($2.1)	($25.2)	($0.2)	$22.9	$1.0	$1.6	$0.0	($0.6)	$22.3	2%
13	Tiltonsville - Windsor	Line	AP	$6.0	($17.5)	$1.4	$24.9	($3.5)	$1.1	($0.9)	($5.5)	$19.4	1%
14	Unclassified	Unclassified	Unclassified	$0.7	($10.5)	$6.2	$17.4	$0.0	$0.0	$0.0	$0.0	$17.4	1%
15	Pleasant Valley - Belvidere	Line	ComEd	($17.5)	($37.7)	$3.5	$23.7	$0.2	$3.1	($4.9)	($7.8)	$15.9	1%
16	Graceton - Raphael Road	Line	BGE	$9.1	($3.8)	$0.6	$13.6	$0.4	($1.3)	($0.2)	$1.5	$15.1	1%
17	Brunner Island - Yorkana	Line	Met-Ed	$2.8	($9.9)	$0.4	$13.0	$1.2	($0.6)	($0.9)	$1.0	$14.0	1%
18	Crescent	Transformer	DLCO	$5.6	($7.5)	$0.8	$13.9	($0.1)	($0.6)	($1.0)	($0.4)	$13.5	1%
19	Clover	Transformer	Dominion	$2.8	($11.1)	$2.1	$15.9	($1.1)	($1.1)	($3.2)	($3.3)	$12.6	1%
20	Millville - Sleepy Hollow	Line	Dominion	$6.2	($5.8)	$0.3	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
21	Millville - Old Chapel	Line	Dominion	$2.9	($8.3)	$1.0	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	1%
22	Branchburg - Readington	Line	PSEG	($4.7)	($17.7)	$0.7	$13.7	($0.3)	$1.6	$0.2	($1.8)	$11.9	1%
23	Kanawha - Kincaid	Line	AEP	$6.1	($4.0)	$1.5	$11.6	$0.0	$0.0	$0.0	$0.0	$11.6	1%
24	Pleasant Prairie - Zion	Flowgate	MISO	($4.2)	($8.7)	$3.0	$7.5	($0.4)	$1.2	($16.7)	($18.4)	($10.9)	(1%)
25	Eddystone - Island Road	Line	PECO	$3.1	($5.4)	$1.1	$9.6	($0.0)	($0.0)	$0.0	($0.0)	$9.5	1%

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): Calendar year 2011

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($32.9)	($66.4)	($5.3)	$28.2	$6.3	$6.7	($4.5)	($4.9)	$23.3	3,354	1,115
2	Oak Grove - Galesburg	($13.6)	($22.0)	$6.3	$14.6	($2.5)	$6.0	($20.8)	($29.3)	($14.7)	1,736	1,131
3	Bunsonville - Eugene	($11.5)	($19.0)	$2.1	$9.6	$0.0	($0.0)	($0.0)	($0.0)	$9.6	2,444	11
4	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.3)	($0.1)	($5.7)	($5.8)	($5.6)	24	302
5	Burnham - Munster	($10.9)	($19.0)	($3.0)	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	1,152	0
6	Stillwell	($0.0)	($0.4)	($0.1)	$0.3	($0.3)	$1.3	($3.6)	($5.2)	($4.9)	93	88
7	Michigan City - Laporte	($10.4)	($16.4)	$3.0	$9.0	($1.7)	($1.3)	($3.8)	($4.2)	$4.8	2,935	632
8	Pleasant Prairie - Zion	($1.2)	($2.3)	$2.0	$3.1	($0.1)	($0.5)	($7.9)	($7.5)	($4.4)	839	210
9	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.4	$0.3	($4.4)	($4.2)	($4.2)	0	213
10	Cook - Palisades	($1.3)	($5.2)	$0.3	$4.1	$0.0	$0.0	($0.2)	($0.2)	$3.9	481	9
11	Rantoul - Rantoul Jct	($3.2)	($5.5)	$0.6	$3.0	$0.1	$0.0	($0.5)	($0.4)	$2.6	553	188
12	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$0.8	$1.2	($2.8)	($3.2)	($2.2)	67	132
13	St John - Liberty Park	($1.8)	($6.0)	$0.6	$4.8	$0.6	$1.0	($2.2)	($2.6)	$2.2	334	161
14	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	($1.8)	($2.1)	($2.1)	0	56
15	Temporary Monticello - E Wiinamac	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.5	($1.2)	($1.7)	($1.7)	0	69
16	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($1.7)	($1.6)	($1.6)	0	107
17	Cumberland - Bush	($1.0)	($5.8)	$2.1	$6.9	$0.2	$0.9	($4.6)	($5.3)	$1.6	1,599	215
18	Rising	($5.2)	($8.1)	($0.1)	$2.8	$0.0	$1.1	($3.3)	($4.4)	($1.6)	947	175
19	Green Acres - St John	$0.0	$0.0	$0.0	$0.0	$0.6	$1.4	($0.7)	($1.5)	($1.5)	0	147
20	Rantoul Jct - Sidney	($1.0)	($2.0)	$0.1	$1.1	$0.5	$0.0	($0.2)	$0.3	$1.3	62	113

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): Calendar year 2010

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($46.0)	($88.6)	($5.1)	$37.4	$1.4	$0.2	($9.0)	($7.8)	$29.6	2,051	810
2	Pleasant Prairie - Zion	($4.2)	($8.7)	$3.0	$7.5	($0.4)	$1.2	($16.7)	($18.4)	($10.9)	1,321	404
3	Benton Harbor - Palisades	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.8	($4.5)	($5.3)	($5.2)	11	114
4	Rising	($1.7)	($6.8)	$0.9	$6.0	($0.1)	$0.6	($0.9)	($1.6)	$4.4	875	80
5	Oak Grove - Galesburg	($0.3)	($0.6)	$0.2	$0.4	($0.2)	$0.7	($3.0)	($3.9)	($3.4)	114	242
6	Dunes Acres - Michigan City	($0.3)	($1.5)	$0.9	$2.1	($0.1)	($0.3)	$0.4	$0.6	$2.7	264	42
7	Palisades - Vergennes	$1.1	($2.2)	$0.5	$3.9	($0.1)	$0.5	($0.9)	($1.5)	$2.4	235	91
8	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($2.0)	($2.1)	($2.1)	0	76
9	Burnham - Sheffield	($1.8)	($3.3)	$0.4	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	252	0
10	Cook - Palisades	$0.0	($0.1)	$0.1	$0.2	($0.3)	$0.2	($1.5)	($2.0)	($1.7)	13	39
11	Paxton - Sidney	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	($1.4)	($1.5)	($1.5)	0	29
12	Burr Oak	$0.2	($0.2)	$0.0	$0.4	$0.4	$0.4	($1.9)	($1.8)	($1.5)	140	210
13	State Line - Wolf Lake	$0.1	($0.9)	$0.6	$1.5	($0.1)	$0.0	($0.0)	($0.1)	$1.4	376	7
14	Marktown - Inland Steel	($0.7)	($2.2)	$0.7	$2.2	($0.9)	$0.8	($1.4)	($3.1)	($0.9)	424	344
15	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.8)	($0.9)	($0.9)	0	51
16	Michigan City - Laporte	($0.0)	($0.2)	$0.1	$0.3	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	50	67
17	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($0.5)	($0.5)	0	48
18	Beaver Valley - Sammis	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.2)	($0.4)	($0.4)	0	8
19	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	23
20	Stillwell - Dumont	($0.2)	($0.4)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	42	0

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for year 2010 and 2011 respectively. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2011, the AP South interface constraint contributed to positive congestion. There were no significant contributions to negative congestion from 500 kV constraints in 2011.

Congestion Costs by Physical and Financial Participants

In the PJM market, both physical and financial participants make virtual supply offers (increments) and virtual demand bids (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are considered a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company. In 2011, financial companies as a group were net recipients of congestion credits, whereas physical companies were net payers of congestion charges.[38] In 2011, financial companies received net $108.2 million, a decrease of $60.3 million or 35.8 percent compared to 2010. In 2011, physical companies paid net $1,107.2 million in congestion charges, a decrease of $484.9 million or 30.5 percent compared to 2010.

38 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

Table 10-31 Regional constraints summary (By facility): Calendar year 2011

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$96.1	($140.1)	($0.1)	$236.1	$18.7	$16.0	$0.0	$2.8	$238.9	4,111	1,013
2	5004/5005 Interface	Interface	500	($25.2)	($101.5)	($4.6)	$71.7	$16.1	$19.3	$7.6	$4.3	$76.1	905	470
3	West	Interface	500	($19.3)	($83.4)	($5.0)	$59.1	$0.2	$0.1	$0.1	$0.3	$59.3	867	20
4	AEP-DOM	Interface	500	$14.6	($21.5)	$2.1	$38.2	$2.0	$1.5	($0.4)	$0.1	$38.3	1,786	185
5	Bedington - Black Oak	Interface	500	$10.9	($14.6)	($2.0)	$23.5	$0.2	$0.1	$0.0	$0.1	$23.7	679	7
6	East	Interface	500	($11.5)	($31.5)	($1.2)	$18.7	$0.2	$1.3	$0.1	($1.0)	$17.8	522	22
7	Cloverdale - Lexington	Line	500	$4.9	($2.9)	$1.3	$9.1	$3.3	$2.1	($3.8)	($2.7)	$6.4	602	427
8	Central	Interface	500	($1.5)	($2.8)	($0.0)	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	118	8
9	Mount Storm - Pruntytown	Line	500	$0.1	($0.2)	$0.0	$0.3	$0.2	$0.0	($0.1)	$0.0	$0.3	29	38
10	Doubs - Mount Storm	Line	500	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	9	4
11	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
12	Kammer	Transformer	500	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
13	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	$0.0	$0.0	0	38
14	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9

Table 10-32 Regional constraints summary (By facility): Calendar year 2010

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$128.3	($292.9)	($2.3)	$419.0	$15.5	$15.7	$1.5	$1.3	$420.2	4,622	1,516
2	Bedington - Black Oak	Interface	500	$44.6	($60.3)	$2.7	$107.7	$0.7	$1.9	($1.6)	($2.9)	$104.8	2,283	212
3	5004/5005 Interface	Interface	500	($14.6)	($106.4)	$0.0	$91.8	$12.3	$10.8	($1.3)	$0.1	$92.0	1,642	605
4	AEP-DOM	Interface	500	$10.2	($53.0)	$2.5	$65.8	$0.5	$1.2	($2.8)	($3.5)	$62.3	691	187
5	Cloverdale - Lexington	Line	500	$19.6	($11.2)	$3.0	$33.7	($2.5)	($3.4)	($5.5)	($4.7)	$29.1	1,128	684
6	Mount Storm - Pruntytown	Line	500	$11.8	($10.4)	$2.1	$24.3	$2.0	($2.9)	($4.8)	$0.1	$24.4	571	574
7	West	Interface	500	($2.1)	($25.2)	($0.2)	$22.9	$1.0	$1.6	$0.0	($0.6)	$22.3	181	65
8	East	Interface	500	($2.5)	($10.2)	$0.1	$7.8	($0.0)	($0.0)	$0.0	$0.0	$7.8	256	8
9	Harrison - Pruntytown	Line	500	$1.8	($4.2)	$0.8	$6.9	$0.4	$0.6	($2.7)	($2.9)	$4.0	231	223
10	Central	Interface	500	($0.9)	($2.2)	$0.1	$1.4	$0.2	$0.1	($0.1)	($0.0)	$1.4	117	13
11	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.3)	($0.3)	0	5
12	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	$1.0	$1.3	($0.1)	($0.3)	($0.3)	0	45
13	Harrison Tap - North Longview	Line	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
14	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	1

Table 10-33 Congestion cost by the type of the participant: Calendar year 2011

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$80.3	$28.1	$70.7	$122.8	($44.6)	$12.2	($174.2)	($231.0)	$0.0	($108.2)
Physical	($44.0)	($1,169.9)	($3.8)	$1,122.1	$120.6	$119.7	($15.9)	($15.0)	$0.0	$1,107.2
Total	$36.2	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$0.0	$999.0

Table 10-34 Congestion cost by the type of the participant: Calendar year 2010

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$65.5	$31.5	$84.8	$118.9	($84.3)	$29.2	($173.9)	($287.4)	($0.0)	($168.5)
Physical	$185.9	($1,396.3)	$12.1	$1,594.3	$84.1	$80.8	($5.4)	($2.1)	($0.0)	$1,592.1
Total	$251.4	($1,364.9)	$96.9	$1,713.1	($0.1)	$110.1	($179.3)	($289.5)	$0.0	$1,423.6

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 including the June 1, 2011, ATSI integration. Wind projects account for approximately 37,792 MW, 41.7 percent of the capacity in the queues, and combined-cycle projects account for 34,138 MW, 37.6 percent of the capacity in the queues.

- **New Generation.** Five large plants (over 500 MW) began generating in PJM in 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone.[1] This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002.

- **Generation Retirements.** A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. Overall, 5,191.1 MW, or 29.6 percent of all retirements, are expected in the AEP zone.

- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although changes in environmental regulations have had an impact on coal units throughout the footprint.

Generation and Transmission Interconnection Planning Process

- Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[2] The process is complex and time consuming as a result of the nature of the required analyses. The cost and time associated with interconnecting to the grid potentially create barriers to entry by creating uncertainty for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built. These projects may also create barriers to entry for projects that would otherwise be completed by creating uncertainty and increasing interconnection costs.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland. The total planned costs for all of these projects are approximately five billion dollars.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between

1 Fremont Energy Center entered PJM after the June 1, 2011 integration of ATSI, and is included in the 5,008 MW of nameplate capacity reported above.

2 OATT Parts IV & VI.

transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[3] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[4,5] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 180,000 MW following the ATSI integration in 2011. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[6]

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2011[7]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011	5,008

In 2011, five new plants of over 500 MW came online in PJM, the first time since 2006 a plant rated at over 500 MW came online. Combined cycle plants accounted for four of the five plants to come online in PJM, while a coal steam plant was the fifth. Fremont Energy Center came online after the integration of the ATSI zone on June 1, 2011.

Table 11-2 Capacity additions of plants greater than 500 MW: Calendar year 2011

Plant Name	Zone	Unit Type	ICAP (MW)
Dresden Energy Facility	AEP	Combined Cycle	545
Longview Power	APS	Coal Steam	700
Fremont Energy Center	ATSI	Combined Cycle	685
Bear Garden Generating Station	Dominion	Combined Cycle	590
York Energy Center	PECO	Combined Cycle	565

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months until Queue T, when new queues began to open annually. Queue X was active through January 31, 2012.

Capacity in generation request queues for the eight year period beginning in 2011 and ending in 2018 increased by 14,309 MW from 76,415 MW in 2010 to 90,725 MW in 2011, or 19 percent (Table 11-3).[8] Queued capacity

3 See 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

4 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

5 *Id.* at PP 313–322.

6 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or deratings.

7 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

8 See the *2010 State of the Market Report for PJM* (March 10, 2011), pp. 205-206, for the queues in 2010.

scheduled for service in 2011 decreased from 25,378 MW to 13,737 MW, or 46 percent. Queued capacity scheduled for service in 2012 increased from 13,261 MW to 13,447 MW, or 1 percent. The 90,725 MW includes generation with scheduled in-service dates in 2011 and units still active in the queue with in-service dates scheduled before 2011, listed at nameplate capacity, although these units are not yet in service.

Table 11-3 Queue comparison (MW): December 31, 2011 vs. December 31, 2010

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	13,737	(11,641)	(46%)
2012	13,261	13,447	186	1%
2013	11,244	13,051	1,808	16%
2014	13,888	17,036	3,148	23%
2015	5,960	19,251	13,291	223%
2016	1,350	9,288	7,938	588%
2017	2,140	1,720	(420)	(20%)
2018	3,194	3,194	0	0%
Total	76,415	90,725	14,309	19%

Table 11-4 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[9]

Data presented in Table 11-5 show that through 2011, 40.6 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.9 percent was from Queues C, D and E.[10] As of December 31, 2011, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.6 percent of all queued capacity has been placed in service.

The data presented in Table 11-5 show that for successful projects there is an average time of 802 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 483 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Capacity in PJM queues (MW): At December 31, 2011[11,12]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,086	555	17,409	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	150	2,345	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	3,978	4,482
N Expired 31-Jan-05	177	2,143	173	7,913	10,407
O Expired 31-Jul-05	966	1,471	872	4,283	7,592
P Expired 31-Jan-06	502	2,625	655	4,908	8,690
Q Expired 31-Jul-06	1,109	1,454	3,408	8,643	14,614
R Expired 31-Jan-07	4,587	1,366	608	16,194	22,755
S Expired 31-Jul-07	2,337	3,198	383	11,475	17,393
T Expired 31-Jan-08	11,425	927	471	14,845	27,667
U Expired 31-Jan-09	6,005	226	621	26,506	33,357
V Expired 31-Jan-10	10,837	152	1,800	4,332	17,122
W Expired 31-Jan-11	13,659	22	1,179	9,420	24,280
X Expires 31-Jan-12	28,121	0	104	1,602	29,827
Total	79,745	31,403	10,980	204,931	327,059

Table 11-5 Average project queue times (days): At December 31, 2011

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	844	648	0	4,420
In-Service	802	668	0	3,602
Suspended	2,448	925	704	4,103
Under Construction	1,211	826	0	4,370
Withdrawn	483	490	0	3,186

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity. There has been a substantial increase in combined cycle units added to the queues. On December 31, 2011, there were 34,788 MW of capacity from combined cycle units in the queue, compared to 16,451 MW in 2010, an increase of 111.5 percent.

9 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

10 The data for Queue X include projects through December 31, 2011.

11 The *2011 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

12 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2011

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,775	753	9	0	0	685	15	0	2,541	5,779
AEP	4,355	0	77	70	0	118	1,346	0	13,026	18,991
AP	930	0	8	98	0	223	597	32	1,065	2,954
ATSI	268	72	22	0	30	52	135	0	947	1,525
BGE	678	0	29	0	1,640	0	132	0	0	2,479
ComEd	1,080	483	103	23	607	95	1,366	0	14,841	18,597
DAY	0	0	2	112	0	33	12	0	1,685	1,844
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	6,171	595	12	0	1,669	90	429	52	984	10,002
DPL	1,759	56	0	0	0	337	22	34	850	3,058
JCPL	2,729	27	30	0	0	1,178	0	0	0	3,964
Met-Ed	3,510	0	21	0	39	183	0	3	0	3,756
PECO	663	7	6	0	490	21	0	2	0	1,189
PENELEC	905	20	5	0	0	56	146	0	1,565	2,697
Pepco	5,547	0	6	0	0	10	0	0	0	5,563
PPL	1,354	11	4	3	1,700	146	34	20	268	3,540
PSEG	3,065	1,083	9	0	50	361	105	2	20	4,695
Total	34,788	3,108	343	306	6,316	3,589	4,339	145	37,792	90,725

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2011[13]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	9,990	1,926	54	0	540	2,583	142	38	3,411	18,684
SWMAAC	6,225	0	35	0	1,640	10	132	0	0	8,042
WMAAC	5,769	31	30	3	1,739	385	180	23	1,833	9,993
Non-MAAC	12,804	1,150	224	303	2,397	611	3,885	84	32,548	54,005
Total	34,788	3,108	343	306	6,316	3,589	4,339	145	37,792	90,725

Table 11-8 Existing PJM capacity: At December 31, 2011[14] (By zone and unit type (MW))

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	154	661	21	0	0	37	1,110	0	8	1,990
AEP	4,912	3,676	59	1,073	2,094	0	21,571	0	1,553	34,938
AP	1,129	1,180	36	80	0	0	8,451	27	799	11,702
ATSI	685	1,661	52	0	2,134	0	7,998	0	0	12,530
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,763	7,178	86	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	4,025	3,761	167	3,589	3,558	0	8,283	0	0	23,383
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	990	0	66	439	0	6,289	0	185	8,943
JCPL	1,693	1,225	33	400	615	0	15	0	0	3,980
Met-Ed	2,041	416	42	20	805	0	844	0	0	4,167
PECO	3,209	836	7	1,642	4,541	3	1,505	1	0	11,743
PENELEC	0	344	46	513	0	0	6,834	0	630	8,366
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,527	0	220	11,274
PSEG	2,960	2,863	5	5	3,493	83	2,125	0	0	11,534
Total	26,953	30,725	764	7,975	34,051	124	92,464	28	5,339	198,424

13 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

14 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 11-6 shows the projects under construction or active as of December 31, 2011, by unit type and control zone. Most of the steam projects (93.7 percent of the MW) and most of the wind projects (90.9 percent of the MW) are outside the Eastern MAAC (EMAAC)[15] and Southwestern MAAC (SWMAAC)[16] locational deliverability areas (LDAs).[17] Of the total capacity additions, only 18,684 MW, or 20.5 percent, are projected to be in EMAAC, while 8,042 MW or 8.9 percent are projected to be constructed in SWMAAC. Of total capacity additions, 36,719 MW, or 40.4 percent of capacity, is being added inside MAAC zones. Overall, 70.5 percent of capacity is being added outside EMAAC and SWMAAC, and 59.5 percent of capacity is being added outside MAAC zones.

Wind projects account for approximately 37,792 MW of capacity or 41.7 percent of the capacity in the queues and combined-cycle projects account for 34,788 MW of capacity or 37.6 percent of the capacity in the queues.[18] Wind projects account for 3,423 MW of capacity in MAAC LDAs, or 14.3 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 3,411 MW of capacity, or 18.3 percent.

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units are replaced by units burning natural gas. Table 11-7 shows that in the EMAAC LDA, gas burning unit types account for 60.3 percent of the capacity additions. Steam additions (coal) account for 0.8 percent of the MW and solar projects account for 13.8 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 97.8 percent of the MW capacity additions in the SWMAAC LDA. The wind and solar capacity in this section are reported at nameplate capacity and not at derated levels.

Table 11-8 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 11-6) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although changes in environmental regulations and natural gas costs are expected to have an impact on coal units throughout the footprint.

Table 11-9 shows the age of PJM generators by unit type. As most steam units in PJM are from 30 to 60 years old, it appears likely that significant and disproportionate retirements of steam units will occur within the next 10 to 20 years, particularly if stricter environmental regulations make steam units more costly to operate. While steam units comprise 46.6 percent of all current MW, steam units 40 years of age and older comprise 81.1 percent of all MW 40 years of age and older and 87.2 percent of such MW if hydroelectric is excluded from the total. Approximately 7,930 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC, or 15.7 percent of all steam units 40 years and older.

Table 11-10 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. In 2018, CC and CT generators would account for 57.9 percent of EMAAC generation, an increase of 9.4 percentage points from 2011 levels. Accounting for the fact that about 925 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from 51.2 percent to 57.9 percent. The proportion of gas-fired capacity in EMAAC would increase to 62.0 percent if the derating to 13 percent of nameplate for wind capacity is reflected, meaning that the effective capacity additions are 15,716 MW.

15 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

16 SWMAAC consists of the BGE and Pepco Control Zones.

17 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

18 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 38,301 MW of wind resources and 3,589 MW of solar resources, the 90,725 MW currently active in the queue would be reduced to 55,620 MW.

Table 11-9 PJM capacity (MW) by age: at December 31, 2011

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	19,000	8,814	400	11	0	124	1,864	28	5,305	35,547
11 to 20	5,927	12,557	113	48	0	0	3,390	0	34	22,069
21 to 30	1,584	1,700	55	3,448	15,359	0	7,870	0	0	30,017
31 to 40	244	2,935	43	105	16,344	0	28,862	0	0	48,533
41 to 50	198	4,719	138	2,915	2,349	0	30,418	0	0	40,737
51 to 60	0	0	15	379	0	0	16,971	0	0	17,365
61 to 70	0	0	0	0	0	0	2,939	0	0	2,939
71 to 80	0	0	0	284	0	0	95	0	0	379
81 to 90	0	0	0	549	0	0	54	0	0	603
91 to 100	0	0	0	151	0	0	0	0	0	151
101 and over	0	0	0	84	0	0	0	0	0	84
Total	26,953	30,725	764	7,975	34,051	124	92,464	28	5,339	198,424

Table 11-10 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[19]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Combined Cycle	198	2.2%	9,141	26.8%	9,990	18,933	42.5%
	Combustion Turbine	2,484	28.0%	7,358	21.6%	1,926	6,801	15.3%
	Diesel	53	0.6%	162	0.5%	54	162	0.4%
	Hydroelectric	2,042	23.0%	2,047	6.0%	0	620	1.4%
	Nuclear	615	6.9%	8,648	25.4%	540	8,574	19.3%
	Solar	0	0.0%	123	0.4%	2,583	2,706	6.1%
	Steam	3,472	39.2%	6,580	19.3%	142	3,250	7.3%
	Storage	0	0.0%	1	0.0%	38	39	0.1%
	Wind	0	0.0%	8	0.0%	3,411	3,419	7.7%
	EMAAC Total	8,863	100.0%	34,067	100.0%	18,684	44,503	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	6,225	6,455	44.2%
	Combustion Turbine	777	14.8%	2,162	18.3%	0	1,384	9.5%
	Diesel	0	0.0%	19	0.2%	35	54	0.4%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	22.9%
	Solar	0	0.0%	0	0.0%	10	10	0.1%
	Steam	4,459	85.2%	7,686	65.1%	132	3,359	23.0%
	SWMAAC Total	5,236	100.0%	11,801	100.0%	8,042	14,607	100.0%
WMAAC	Combined Cycle	0	0.0%	3,851	16.2%	5,769	9,620	60.7%
	Combustion Turbine	559	6.1%	1,377	5.8%	31	850	5.4%
	Diesel	46	0.5%	136	0.6%	30	120	0.8%
	Hydroelectric	887	9.6%	1,113	4.7%	3	1,116	7.0%
	Nuclear	0	0.0%	3,275	13.8%	1,739	5,014	31.7%
	Solar	0	0.0%	0	0.0%	385	385	2.4%
	Steam	7,737	83.8%	13,205	55.5%	180	5,648	35.7%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	850	3.6%	1,833	2,683	16.9%
	WMAAC Total	9,228	100.0%	23,807	100.0%	9,993	15,838	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,731	10.7%	12,804	26,535	18.3%
	Combustion Turbine	900	2.3%	19,829	15.4%	1,150	20,079	13.8%
	Diesel	53	0.1%	447	0.3%	224	619	0.4%
	Hydroelectric	1,434	3.7%	4,814	3.7%	303	5,118	3.5%
	Nuclear	1,734	4.5%	20,423	15.9%	2,397	21,086	14.5%
	Solar	0	0.0%	1	0.0%	611	612	0.4%
	Steam	34,811	89.4%	64,994	50.5%	3,885	34,068	23.5%
	Storage	0	0.0%	27	0.0%	84	111	0.1%
	Wind	0	0.0%	4,482	3.5%	32,548	37,030	25.5%
	Non-MAAC Total	38,931	100.0%	128,749	100.0%	54,005	145,257	100.0%
All Areas	Total	62,258		198,424		90,725	220,206	

19 Percentages shown in Table 11-10 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 64.3 percent of all new capability in EMAAC and 76.5 percent when the derating of wind capacity is reflected.

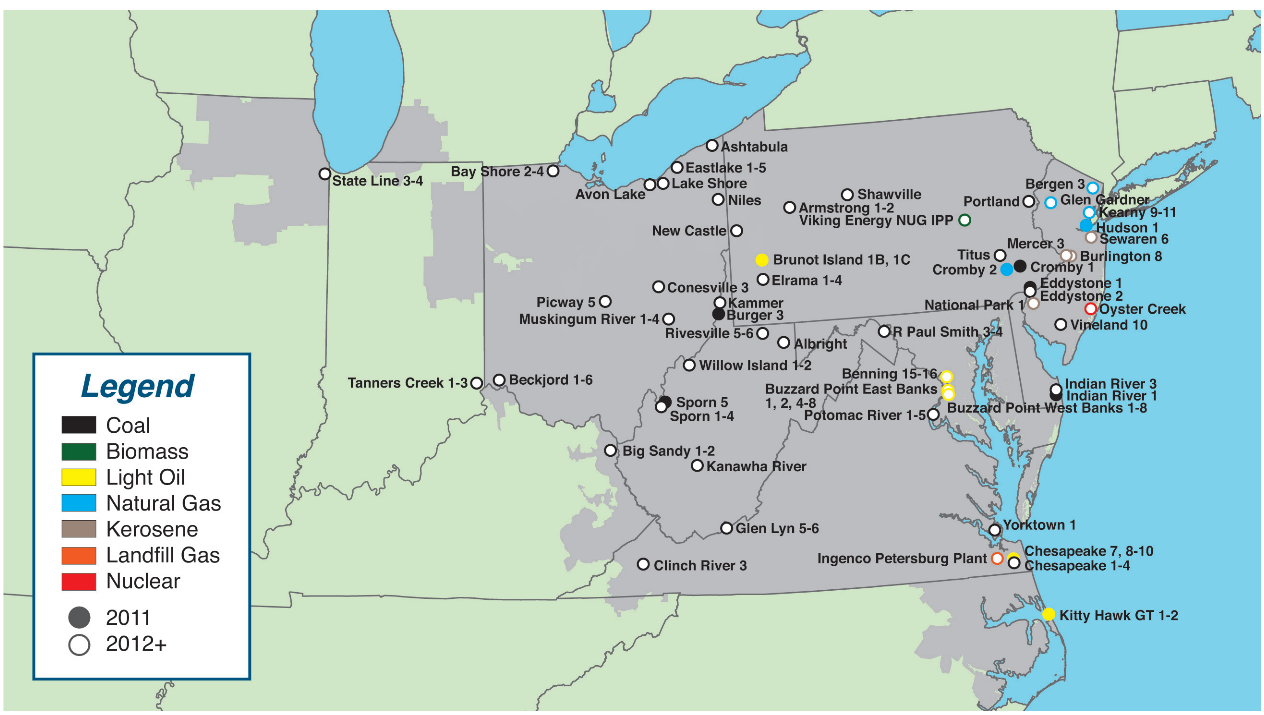
There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 97.2 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 53.7 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[20] In these zones, 89.4 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 25.7 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

Planned Deactivations

As shown in Table 11-12, 17,563.7 MW are planning to deactivate by the end of calendar year 2019. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. Of planned deactivations in 2012, approximately 2,185 MW, or 30.4 percent are located in the ATSI zone. Overall, 5,191.1 MW, or 29.6 percent of all retirements, are expected in the AEP zone. More retirements due to aging units lacking emission control technology are expected, particularly to comply with environmental regulations that will be in effect by 2015. Figure 11-1 shows plant retirements throughout the PJM footprint, with notable retirements in nearly every PJM state. Table 11-12 and Figure 11-1 do not include the planned retirements of Fisk 19 and Crawford 7&8, due to uncertain deactivation dates. Fisk 19, a 328 MW unit in the ComEd zone, will retire by December 31, 2012. Crawford 7&8 (532 MW total) will retire by December 31, 2014, but could retire as early as 2012.[21] A total of 1,322.3 MW retired in 2011, and it is expected that a total of 18,886 MW will have retired by 2019, with most of this capacity retiring by the end of 2015.

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019



20 Non-MAAC zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

21 See "Edison International Reports 2011 Results" <http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=7865> Accessed March 1, 2012

Table 11-11 Summary of PJM unit retirements (MW): Calendar year 2011 through 2019[22]

	MW
Retirements 2011	1,322.3
Planned Retirements 2012	7,189.0
Planned Retirements Post-2012	10,374.7
Total	18,886.0

Table 11-12 Planned deactivations of PJM units in Calendar year 2012 as of March 1, 2012[23,24,25]

Unit	Zone	MW	Projected Deactivation Date
Sporn 5	AEP	440.0	31-Dec-11
State Line 3-4	ComEd	515.0	01-Apr-12
Viking Energy NUG IPP	PPL	16.0	01-Mar-12
Beckjord 1-3	DEOK	316.0	01-May-12
Benning 15-16	Pepco	548.0	31-May-12
Buzzard Point East Banks 1, 2, 4-8	Pepco	112.0	31-May-12
Buzzard Point West Banks 1-8	Pepco	128.0	31-May-12
Eddystone 2	PECO	309.0	31-May-12
Niles	ATSI	217.0	01-Jun-12
Elrama 1-4	DLCO	460.0	01-Jun-12
Kearny 10-11	PSEG	250.0	01-Jun-12
Vineland 10	AECO	23.0	01-Sep-12
Albright	APS	283.0	01-Sep-12
Armstrong 1-2	APS	343.0	01-Sep-12
R Paul Smith 3-4	APS	115.0	01-Sep-12
Rivesville 5-6	APS	121.0	01-Sep-12
Willow Island 1-2	APS	217.0	01-Sep-12
Ashtabula	ATSI	210.0	01-Sep-12
Bay Shore 2-4	ATSI	419.0	01-Sep-12
Eastlake 1-5	ATSI	1,149.0	01-Sep-12
Lake Shore	ATSI	190.0	01-Sep-12
Potomac River 1-5	Pepco	482.0	01-Oct-12
Total		6,863.0	

Table 11-13 Planned deactivations of PJM units after calendar year 2012, as of March 1, 2012[26]

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Indian River 3	DPL	169.7	31-Dec-13
Big Sandy 1-2	AEP	1,078.0	31-Dec-14
Clinch River 3	AEP	230.0	31-Dec-14
Conesville 3	AEP	165.0	31-Dec-14
Glen Lyn 5-6	AEP	325.0	31-Dec-14
Kammer	AEP	600.0	31-Dec-14
Kanawha River	AEP	400.0	31-Dec-14
Muskingum River 1-4	AEP	790.0	31-Dec-14
Picway 5	AEP	95.0	31-Dec-14
Sporn	AEP	580.0	31-Dec-14
Tanners Creek 1-3	AEP	488.1	31-Dec-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1	Dominion	159.0	31-Dec-14
Portland	Met-Ed	401.0	01-Jan-15
Beckjord 4-6	DEOK	802.0	01-Apr-15
Avon Lake	ATSI	732.0	01-Apr-15
New Castle	ATSI	330.5	01-Apr-15
Titus	Met-Ed	243.0	01-Apr-15
Shawville	PENELEC	597.0	01-Apr-15
Glen Gardner	JCPL	160.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8	PSEG	21.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 6	PSEG	105.0	01-Jun-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		9,842.7	

As shown in Table 11-14, 6,663.5 MW of capacity is at risk for retirement due to its status as a High Electric Demand Day unit in the state of New Jersey. Of these HEDD units, 4,271.5 MW or 64 percent, are in the PSEG zone. While some of these units may retire due to lacking the emission controls needed, others will likely be retro-fitted to comply with New Jersey environmental regulations. Of these, 714 MW have already submitted a retirement notice to PJM.

22 These totals include the retirements of Fisk 19 and Crawford 7&8.

23 See "Pending Deactivation Requests" <http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (Accessed March 1, 2012).

24 Sporn 5 retired February 13, 2012, following a decision by the Ohio PUC.

25 See "GenOn Reports 2011 Results and Announces Expected Deactivation of Generation Units"<http://phx.corporate-ir.net/phoenix.zhtml?c=124294&p=irol-newsArticle&ID=1667152&highlight=> (Accessed March 1, 2012)

26 See "AEP Shares Plan For Compliance With EPA Regulations" <http://www.aep.com/newsroom/newsreleases/?id=1697> (Accessed March 1, 2012)

Table 11-14 HEDD Units in PJM as of December 31, 2011[27]

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Actual Generation Deactivations in 2011

Table 11-15 shows unit deactivations for 2011.[28] A total of 1,322.3 MW retired in 2011, including 94.0 MW from FirstEnergy Corp., 90.0 MW from NRG Energy Inc., 101.3 MW from Dominion Resources, Inc., 30.0 MW from GenOn Energy, Inc., 624.0 MW from Exelon Corporation, and 383.0 MW from Public Service Enterprise Group Incorporated. The retirements were 607.0 MW of coal, 131.3 MW of light oil, and 584.0 MW of natural gas generation. Of these retirements, 624.0 MW were in the PECO zone, 30.0 MW in the DLCO zone, 101.3 MW in the Dominion zone, 90.0 MW in the DPL zone, 94.0 MW in the ATSI zone, and 383.0 MW in the PSEG zone.

27 See "Current New Jersey Turbines that are HEDD Units" <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed March 1, 2012)

28 "*PJM Generator Deactivations*," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 1, 2012).

Generation and Transmission Interconnection Planning Process

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[29] The process is complex and time consuming as a result of the nature of the required analyses. The cost and time associated with interconnecting to the grid potentially create barriers to entry by creating uncertainty for potential entrants.

The queue contains a substantial number of projects that are not likely to be built. These projects may also create barriers to entry for projects that would otherwise be completed by creating uncertainty and increasing interconnection costs. The rules should create the possibility for units that are ready to begin construction to move ahead of units that are not ready and are not making real progress toward being ready to begin construction. The rules should also address the efficient disposition of capacity injection rights associated with retired or mothballed units to ensure that they are not used to block units in the queue from proceeding.

On February 29, 2012, PJM filed interconnection queue process reforms with the Commission that PJM explained "are intended to relieve bottlenecks in the interconnection queue and provide for greater certainty and transparency."[30] The specific proposals include: (i) six-month queue cycles, (ii) "sliding" queues for projects that seek to modify the size of their request by more than a specified amount; (iii) an "alternate queue" for projects less than or equal to 20 MW determined not to have an impact on the PJM grid; (iv) clarified timeframes for notifying PJM if a project is using Capacity Interconnection Rights transferred from a deactivating generator; (v) reduced suspension rights when there is a negative impact on a subsequent project; (vi) modified deposits for certain small projects; and (vii) clarified provisions on the data required for System Impact Studies. The MMU generally supports these proposals in substance and as an indicator of PJM's efforts to address interconnection issues.[31]

29 OATT Parts IV & VI.

30 PJM Filing in Docket No. ER12-1177-000.

31 *Id.*

Table 11-15 Unit deactivations: Calendar year 2011

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Dominion Resources, Inc.	Kitty Hawk GT1	18.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Kitty Hawk GT2	16.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 8	17.5	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 9	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 10	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 7	16.0	Light Oil	Dominion	40	Apr 08, 2011
NRG Energy Inc.	Indian River 1	90.0	Coal	DPL	50	May 01, 2011
Exelon Corporation	Cromby 1	144.0	Coal	PECO	55	May 31, 2011
Exelon Corporation	Eddystone 1	279.0	Coal	PECO	49	May 31, 2011
GenOn Energy, Inc.	Brunot Island 1B	15.0	Light Oil	DLCO	39	Jun 01, 2011
GenOn Energy, Inc.	Brunot Island 1C	15.0	Light Oil	DLCO	39	Jun 01, 2011
FirstEnergy Corp.	Burger 3	94.0	Coal	ATSI	61	Sep 01, 2011
Public Service Enterprise Group Incorporated	Hudson 1	383.0	Natural Gas	PSEG	39	Dec 08, 2011
Exelon Corporation	Cromby 2	201.0	Natural Gas	PECO	54	Dec 31, 2011

Table 11-16 Generation and transmission interconnection timeline

Process Step	Start on	Complete by	Days to complete	Days to decide whether to continue
Feasibility Study	January 31	April 30	90	30
	April 30	July 31		
	October 31	October 31		
	January 31	January 31		
System Impact Study	January 31	June 01	120	30
	April 30	September 01		
	July 31	December 01		
	October 31	March 01		
Facilities Study	Upon acceptance of the Facilities Study Agreement	Varies	Varies	60
Interconnection Service Agreement	Upon acceptance of an Interconnection Service Agreement	Varies	Varies	60
Interconnection Construction Service Agreement	Upon acceptance of Interconnection Construction Service Agreement	Varies	Varies	NA

Table 11-17 Impact Study Agreement deposit requirements

Project Size	Non-Refundable Deposit	Non-Refundable Cost per MW	Refundable Cost per MW	Maximum Deposit
<= 2MW	$5,000	$0	$0	NA
> 2 MW, <= 20 MW	$10,000	$0	$0	NA
> 20 MW, <= 100 MW	$0	$500	$0	NA
> 100 MW	$50,000	$0	$300	$300,000

Participation in the PJM Capacity Market requires procurement of capacity interconnection rights. These rights persist during the unit's lifetime, and expire one year after a unit is retired.[32] The rights persist if, during that additional year, the unit owner submits a new interconnection request at the same point of interconnection.[33]

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process.[34] With the assumption that a facilities study is not required, and accounting for the time required by PJM to complete the required studies, it takes approximately ten months from the initial request for interconnection to the point where the applicant can begin to negotiate an Interconnection Service Agreement. Upon execution of the Interconnection Service Agreement, the parties can then develop an Interconnection Construction Service Agreement, which is used to develop an agreed upon schedule of work for construction (Table 11-16).

Initiating the Planning Process

To initiate the interconnection planning process, an applicant must submit a Feasibility Study Agreement to PJM for execution along with required information about the project and the appropriate fees.[35] The applicant is obligated to pay the actual costs of studies conducted on its behalf. The feasibility study fees depend on when the request is submitted and the size of the interconnection request but the initial deposit cannot exceed $100,000. Resources that are 20 MW or less, or qualify as small resources, can often use an expedited queue process, under which a small resource can receive interim Capacity Interconnection Rights if a queue project is ready to be put in service ahead of other queued projects.

32 OATT § 230.3.3.

33 *Id.*

34 The material in this section is based on PJM Manual M-14A: Generation and Transmission Interconnection Process. "M-14A: Generation and Transmission Interconnection Process", Revision 9 (April 12, 2011).

35 The Feasibility Study Agreements are identified as Attachment N of the PJM Open Access Transmission Tariff (OATT) for generation interconnection requests and Attachment S of the PJM OATT for merchant transmission interconnection requests.

Feasibility Study

A developer is required to elect capacity resource status or energy only resource status. Capacity resource status allows the generator to meet capacity obligations through RPM, while energy resource status allows the unit to participate in the energy market only. In order to qualify as a capacity resource, sufficient transmission capability must exist to ensure the deliverability of the generator output to network load and to satisfy the reliability requirements of the NERC region in which the generator is located.[36]

Feasibility studies are performed four times each year. The feasibility studies are performed by PJM and the affected Transmission Owners (TO), who provide verification of PJM results. The TOs also provide preliminary cost estimates for the project. The feasibility study is limited to short-circuit studies and load-flow analysis of probable contingencies, and does not include a stability analysis. In general, the feasibility study will be completed within 90 days.

System Impact Study

If the developer decides to proceed with the System Impact Study, they must pay the transmission provider a deposit (Table 11-17).[37]

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation or transmission facility to the system including the impact on deliverability to PJM load in the region where the generator or transmission facility is located. The System Impact Study identifies the system constraints relating to the new project and the necessary attachment facilities, local upgrades and network upgrades required to maintain reliability and deliverability in the region. The System Impact Studies are performed by PJM staff, in coordination with the affected TOs, who provide verification of PJM results. The TOs also provide more comprehensive cost estimates for the project than provided with the feasibility studies. System Impact Studies are performed four times each year.

The System Impact Study considers relationships among the new generator or transmission facility,

36 The PJM footprint includes all or part of Reliability*First* and the SERC Reliability Corporation (SERC) NERC regions.

37 See OATT § 204.3A.

other planned generators in the queue, and the existing system. The System Impact Study includes projects that were in the queue ahead of the project being studied. The Study attempts to model each project in the queue to appropriately identify the dependencies among the projects.

Facilities Study

If the applicant decides to proceed with a Facilities Study, the applicant must submit a required refundable deposit in the amount of $100,000 or the estimated amount of its Facilities Study cost responsibility for the first three months of work on the study, whichever is greater. If the applicant requests a Facilities Study, the results of the System Impact Study are incorporated in the Regional Transmission Expansion Plan (RTEP) Process.

The Facilities Study provides an estimate of the cost to the applicant for attachment facilities, local upgrades and network upgrades necessary to accommodate the project, and an estimate of the time required to complete the design and construction of the facilities and upgrades. The Facilities Studies are performed by the affected TOs. The TOs also provide more accurate cost estimates for the project than provided with feasibility studies and system impact studies. The time to complete a Facilities Study varies depending on the elements under study.

Interconnection Service Agreement

If the applicant decides to proceed with an Interconnection Service Agreement, they must provide PJM with a letter of credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. The applicant must also demonstrate: completion of a fuel deliverability agreement and water agreement (if necessary); control of any necessary rights-of-way for fuel and water interconnections (if necessary); acquisition of any necessary local, county and state site permits; and a signed memorandum of understanding for the acquisition of major equipment. PJM may also request milestone dates for permitting, regulatory certifications, or third party financial arrangements.

Interconnection Construction Service Agreement

Once an Interconnection Service Agreement is executed, PJM is required to tender an Interconnection Construction Service Agreement among the applicant, PJM and the affected Interconnection Transmission Owner(s) within 45 days. The applicant then has 60 days to execute the Interconnection Construction Service Agreement. If the Transmission Owner and the applicant cannot agree upon the terms of the Interconnection Construction Service Agreement, dispute resolution may be requested, and the customer has the option to design and install all or any portion of the Transmission Owner Interconnection Facilities under the "Option to Build" clause.[38]

Backbone Facilities

PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland. The total planned costs for all of these projects are approximately five billion dollars.[39]

On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) to delay the construction of the MAPP transmission line. The PJM RTEP analysis, using the most current economic forecasts, demand response commitments and potential new generation, showed that the MAPP project can be delayed. As a result, the initial MAPP in-service date of 2015 has been moved to 2019-2021. The PJM Board of Managers advised PHI to sustain efforts needed to allow the MAPP project to be resumed when it is needed.[40]

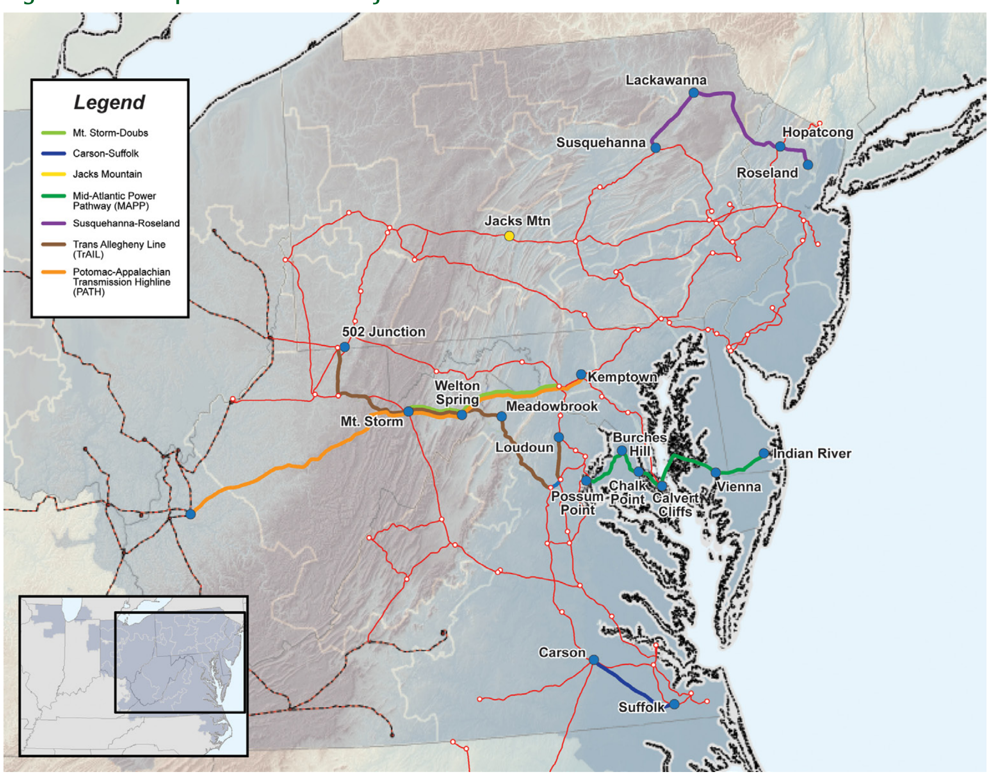
38 See PJM. "PJM Open Access Transmission Tariff", Sixth Revised Sheet No. 224CC (Effective March 1, 2007) Section VI.212.6.

39 Total estimated cost calculated from the backbone project cost estimates found in the "Construction Status Database" located at <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status.aspx>.

40 See "PJM Board directs delay in MAPP Transmission Line,", <http://www.pjm.com/about-pjm/newsroom/newsletter-notices/state-lines/2011/september.aspx#Article_4> (Accessed October 22, 2011).

In early October 2011, the Interagency Rapid Response Team for Transmission named the Susquehanna-Roseland power line project to the initial list of seven transmission line projects for rapid review and permit process. The Rapid Response Team is a federal interagency team consisting of the Department of Agriculture, the Department of Commerce, the Department of Defense, the Department of Energy, the Department of the Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation and the White House Council on Environmental Quality.[41] The Rapid Response Team for Transmission was implemented to coordinate, improve and accelerate the permitting process for critical transmission line projects in order to improve overall reliability of the US power grid.[42]

Figure 11-2 Map of Backbone Projects[43]



Mount Storm – Doubs

The Mount Storm – Doubs transmission line includes 65.7 miles in West Virginia, 30.7 miles in Virginia and 2.8 miles in Maryland. Under this project, the existing transmission towers will be replaced, resulting in an increase in capacity of about 60 percent. The construction will occur within the existing right-of-way. The required in-service date for this project is June 2020. The project is currently estimated to cost between $320 and $370 million.[44,45]

Jacks Mountain

The Jacks Mountain project includes a new 500 kV substation at Jacks Mountain and 1,000 MVARs of capacitors. The project requires the replacement of a wave trap (a device used to divert communication signals sent on the transmission line from the remote substation to the telecommunications/protection panel in the substation control room) and an upgrade of a section at the Keystone 500 kV bus, the replacement of two wave traps at the Juniata 500 kV bus as well as relay changes at the Juniata 500 kV substation. This project has been deemed necessary to resolve voltage problems for load deliverability reliability criteria violations starting on June 1, 2013, and is required to be in service by that date.

Currently, all land required for this project has been procured. The transmission line engineering design is in process, and the detailed substation engineering design is expected to be completed in the summer of 2013. The procurement of transmission line hardware and substation equipment has been scheduled for the middle of 2013, for delivery in 2014. The 500 kV breakers have been ordered, and are scheduled for delivery in October

41 See "Interagency Rapid Response Team for Transmission," <http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission> (Accessed October 28, 2011).

42 See "Energy Projects Energy Infrastructure Update for September 2011," <http://www.ferc.gov/legal/staff-reports/10-21-11-energy-infrastructure.pdf> (Accessed January 30, 2012).

43 Source: PJM © 2011. All rights reserved.

44 See PJM.com. "Mount Storm – Doubs," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx> (Accessed January 1, 2012)

45 See Dominion. "Mt. Storm – Doubs 500kV Rebuild Project,"<http://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (Accessed January 1 ,2012)

2014 and January 2015. The necessary 500 kV capacitor banks are also on order, with a scheduled delivery of January 2015. The 500 kV disconnect switches are on order, with a scheduled delivery of October 2014.[46]

Mid-Atlantic Power Pathway (MAPP)

The MAPP transmission project will serve the District of Columbia, Maryland and Delaware. This project will consist of approximately 69 miles of alternating current lines and 83 miles of direct current lines. The majority of this line will be built on, or adjacent to, existing transmission lines. The project requires a new 500 kV transmission line from the Possum Point to the Calvert Cliffs substations, and two 500 kV High Voltage Direct Current (HVDC) circuits from a new substation in Calvert Cliffs, MD, to a new substation in Wicomico County, MD and to a new substation in Sussex County, DE. Included in these circuits is a submarine cable crossing of the Chesapeake Bay.

Potomac – Appalachian Transmission Highline (PATH)

The Potomac - Appalachian Transmission Highline (PATH) project is required to resolve reliability criteria violations. The PATH project consists of a 765 kV transmission line extending approximately 275 miles from the Amos Substation, which is located in southwestern West Virginia, to the proposed Kemptown (765/500 kV) Substation, located in central Virginia. The project also includes a new Welton Spring (765/500 kV) Substation.

Currently, right-of-way issues are being discussed in West Virginia, Virginia and Maryland. The property for the Welton Spring and Kemptown substations has been acquired. The preliminary engineering design work, as well as the preliminary procurement activities, is in progress. Construction will be scheduled to begin following receipt of state commission approvals to construct. The required in-service date for the PATH line is June 1, 2015.[47]

PJM is in the process of considering new information, including fuel cost estimates, emissions costs, future generation scenarios, load forecast updates and demand response projections.

Susquehanna – Roseland (S-R)

The Susquehanna - Roseland project is a new 500 kV transmission line from Susquehanna, located in central eastern Pennsylvania, to Roseland, located in north central New Jersey, which is required to resolve reliability criteria violations starting on June 1, 2012. The project will require an upgrade of seven 230 kV and one 500 kV substations, as well as three new 500 kV substations, two with a 500/230 kV transformers.

Currently, construction and right-of-way permit applications have been submitted with the National Park Service (NPS). A decision on the applications is not expected from the NPS until October of 2012. Additionally, the issuance of a New Jersey Department of Environmental Protection (NJDEP) Wetland and Flood Hazard Area Permit has also been delayed. While PJM has required an in-service date of June 1, 2012, construction of the project has been delayed as a result. The expected in-service date for the Roseland to Hopatcong portion is June 2014, with the remainder of the project to be completed by June 2015.[48]

In early October 2011, the Interagency Rapid Response Team for Transmission named the Susquehanna—Roseland power line project to the initial list of seven transmission line projects for rapid review and permit process.

Trans Allegheny Line (TrAIL)

The Trans Allegheny Line (TrAIL) project is necessary to meet growing demand in the Mid-Atlantic region and is required to resolve reliability criteria violations starting June 1, 2011. The project includes a new 500 kV transmission line extending from 502 Junction to Loudoun substation, and includes: a 76.8 mile segment from the 502 Junction bus to the Mt. Storm bus; a 60.1 mile segment from the Mt. Storm bus to the Meadowbrook bus; and an 80.8 mile segment from the Meadowbrook bus to the Loudoun bus.

The TrAIL project was completed on May 19, 2011.[49]

46 See PJM.com. "Jacks Mountain," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx> (Accessed January 30, 2012).

47 See PJM.com. "Potomac – Appalachian Transmission Highline (PATH) <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>. (Accessed January 1, 2012)

48 See PJM.com. "Susquehanna – Roseland," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>. (Accessed January 30, 2012).

49 See TrAIL. (2012) <http://www.aptrailinfo.com/index.php>. (2012)

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[50] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs.

As an RTO, PJM is responsible to constantly evaluate the need for transmission investments related to reliability and to help ensure the construction of needed facilities. As the operator and designer of markets, PJM also needs to engage in the economic evaluation of transmission system investments. PJM has made some significant progress in this area.

As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non-market mechanism, typically under traditional regulation.

Economic Valuation Metrics

Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[51] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

PJM performs a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the regional transmission plan that, if accelerated, also could relieve one or more economic constraints; (ii) modifying reliability-based enhancements or expansions already included in the regional transmission plan that, as modified, would relieve one or more economic constraints; (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified.[52] These economic constraints include, but are not limited to, constraints that cause significant historical gross congestion, significant historical unhedgeable congestion, pro-ration of Stage 1B ARR requests or significant congestion as forecasted in the market efficiency analysis. The market efficiency analysis uses the Benefit/Cost Ratio, defined as the present value of the total annual project benefit for each of the first 15 years divided by the present value of the project cost for the first 15 years of the project. To be included in the RTEP, the benefit/cost ratio must be greater than or equal to 1.25.

In the event that the annual review shows changes in the costs and benefits of particular projects, PJM reviews the changes with the TEAC and recommends to the PJM Board whether the project continues to provide measurable benefits and should remain in the RTEP. This yearly evaluation includes changes in cost estimates of the economic-based enhancement or expansion and changes in system conditions such as load forecasts,

50 See PJM OA Schedule 6.

51 See 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

52 The process is defined in Section 1.5.7 of the PJM Tariff. See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed January 28, 2012) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx>. Each year, the assumptions to be used in performing the market efficiency analysis are presented to the PJM Transmission Expansion Advisory Committee (TEAC) for review and comment and the PJM Board approves the assumptions in June of each year.

anticipated merchant transmission facilities, generation and demand response.

This annual review process has the potential to create substantial uncertainty for those building transmission facilities and for all market participants affected by the changes to the transmission system that would result from the completion of these facilities. Significant transmission projects, like the backbone facilities, have substantial impacts on energy and capacity markets and thus on the economics of both generation and load. The locational supply and demand of energy are affected and thus locational energy prices are affected. Changes in expected energy prices determine expected revenues from the energy market and expected payments to the energy market. The locational supply and demand of capacity are affected and thus locational capacity prices are affected. Changes in expected capacity prices determine expected revenues from the capacity market and expected payments to the capacity market. The uncertainty about transmission projects affects decisions about whether to invest in new generation and whether to continue to invest in existing generation. The uncertainty about transmission projects affects decisions about where to locate new load and decisions about whether to invest in demand side resources.

The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

Competitive Grid Development

In Order No. 1000, the FERC requires regional transmission planning processes to modify the criteria for an entity to "propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer."[53,54] Such criteria "must not be unduly discriminatory or preferential."[55]

Order No. 1000 requires, among other things, that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[56] ROFR would continue to apply to transmission projects not included in a regional transmission plan for purposes of cost allocation, and ROFR would continue apply to upgrades to transmission facilities.[57] Order No. 1000 allows, but does not require, competitive bidding to solicit transmission projects or developers.[58] The rule does not override or otherwise affect state or local laws concerning construction of transmission facilities, such as siting or permitting.[59]

53 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011); *see also Primary Power, LLC*, 131 FERC ¶61,015 (2010) (reh'g pending); *Central Transmission, LLC v. PJM Interconnection L.L.C.*, 131 FERC ¶61,243 (2010).
54 Order No. 1000 at PP 323–327.
55 *Id.* at PP 323–324.

56 *Id.* at PP 313–322.
57 *Id.* at P 318–319.
58 *Id.* at P 321 & n.302.
59 *Id.* at PP 337, 339.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

After the introduction of LMP markets, financial transmission rights permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and which creates the funds available to offset congestion costs in an LMP market.[2]

In PJM, Financial Transmission Rights (FTRs) were part of the market design from the inception of LMP markets on April 1, 1998.[3] In PJM, FTRs were available to network service and long-term, firm, point-to-point transmission service customers as an offset to congestion costs from the inception of locational marginal pricing (LMP) on April 1, 1998.

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) and an associated Annual FTR Auction.[4,5] Since then, all PJM members have been eligible to purchase FTRs in auctions. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs. FTR funding has been based on both day ahead and balancing congestion revenues from its initial design.

PJM created the split between ARRs and FTRs in order to both continue to provide the appropriate protection against congestion for load, and to permit any excess transmission capacity on the system to be made available to those market participants who wished to use FTRs to speculate or to hedge positions. This separation substantively changed the definition of FTRs. FTRs no longer represent the rights of load to the congestion offset associated with the physical transmission system, but instead represent the potential offset to congestion costs associated with the excess capability of the transmission system to deliver energy over and above that assigned to ARRs.

Following the introduction of ARRs, it is ARRs which now have the characteristics and rationale that were associated with FTRs when FTRs were introduced. Consistent with this function, ARRs are directly allocated to loads which pay for transmission. ARRs and FTRs do not represent a right to the physical delivery of energy.

Firm transmission service customers have access to ARRs because firm transmission service customers pay the costs of the transmission system that enables firm energy delivery. ARRs provide firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. This financial equivalence is not limited to the Day-Ahead Energy Market. Firm transmission service customers receive requested ARRs to the extent that they are consistent both with the physical capability of the transmission system and with the ARR requests of other eligible customers. ARRs provide the holder with revenues, or charges, based on the price differences across ARR transmission paths and the capacity of those paths, which offset congestion costs. These price differences for ARRs result from the Annual FTR Auction. Network service and firm point-to-point transmission service customers can convert allocated ARRs to the underlying FTR through a process termed self scheduling.

Neither ARRs nor FTRs provide a guarantee that holders will receive compensation equal to the value of

1 See 81 FERC ¶ 61,257, at 62,241 (1997).
2 See Id. at 62, 259–62,260 & n. 123.
3 Id.
4 102 FERC ¶ 61,276 (2003).
5 87 FERC ¶ 61,054 (1999).

congestion across the specific paths identified in their ARRs or FTRs. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

An FTR provides the holder with revenues, or charges, up to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path for each FTR MW. This maximum value is the target allocation of the FTR. This does not make FTRs a day ahead product, nor is the FTR holder guaranteed payments equal to its calculated target allocation. FTR funding has appropriately been based on both day ahead and balancing congestion revenues from its initial design.

FTRs are sold based on the system capability remaining after ARRs are allocated, in order to maximize grid usage and efficiency. FTRs can be used as a hedge against congestion, or to speculate on congestion costs across a certain transmission pathway. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service. Revenues to fund FTRs come from the congestion component of LMP in both the Day-Ahead and Balancing Energy Market. This has been part of the PJM market design from its inception. This market design feature helps ensure that payments to FTR holders remain grounded in actual congestion revenues including both day ahead and balancing thereby preventing FTR holders from receiving a windfall or a penalty if modeling in the FTR auction or the Day-Ahead Market differs from actual congestion in the Real-Time Energy Market.

Differences between calculated target allocations and actual congestion are expected as result of the difficulty of modeling FTRs. When actual congestion, measured as the sum of day ahead and balancing congestion on an FTR path, is less than the target allocation on that path, the FTR is termed underfunded or revenue inadequate. Underfunding and revenue inadequacy are misnomers because they appear to imply that the correct answer is that revenues must fully cover congestion on FTR paths. There is no guarantee of full revenue adequacy for FTRs. The mechanism that has the stated intent of assuring full revenue adequacy for FTRs is in fact a mechanism for self funding of revenue adequacy. FTR holders themselves make up any shortfall. Rather than a revenue adequacy mechanism, this is a mechanism to ensure that revenue shortfalls on specific transmission paths are socialized among all FTR holders and that all FTR holders share in the shortfall proportionately.

The *2011 State of the Market Report for PJM* focuses on the annual ARR allocations, the Long Term FTR Auctions, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011, and the 2011 to 2012 planning period which covers June 1, 2011, through May 31, 2012, as well as the Long Term FTR Auctions which cover June 1, 2012 through May 31, 2015.

Table 12-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior in 2011.
- Performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2012 to 2015 Long Term FTR Auction include the Millville – Old Chapel line, approximately 40 miles northwest of Washington, D.C., and the Burr Oak Flowgate, approximately 60 miles west of Fort Wayne, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2011 to 2012 planning period include the Doubs Transformer, approximately 20 miles northwest of Washington, D.C. and the Bartonsville – Stephens City line, approximately 60 miles west of Washington, D.C. The geographic location of these constraints is shown in Figure 12-1.

  Market participants can also sell FTRs. In the 2012 to 2015 Long Term FTR Auction, total participant FTR sell offers were 251,290 MW, up from 177,540 MW during the 2011 to 2014 Long Term FTR Auction. In the Annual FTR Auction for the 2011 to 2012 planning period, total participant FTR sell offers were 337,510 MW, up from 178,428 MW during the 2010 to 2011 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2011) of the 2011 to 2012 planning period, total participant FTR sell offers were 3,984,782 MW, up from 2,706,728 MW for the same period during the 2010 to 2011 planning period.

- **Demand.** The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a single round of an annual auction, if necessary to avoid related system performance issues.[6] On this basis, PJM currently limits the maximum number of bids that could be submitted by a participant for any individual period in an auction to 10,000 bids.

  In the 2012 to 2015 Long Term FTR Auction, total FTR buy bids increased 1.3 percent from 400,222 MW to 405,504 MW. In the Annual FTR Auction total FTR buy bids and self scheduled bids increased 84.8 percent from 1,764,288 MW to 3,260,695 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 (June through December 2011) planning period increased 42.3 percent from 8,973,645 MW, during the same time period of the prior planning period, to 12,767,075 MW.

  As one of the measures to address underfunding, effective August 5, 2011, PJM no longer allows FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

- **Credit Issues.** There were eight participants that defaulted during the 2011 calendar year and 12 default events. The average default for the 2011 calendar year was $282,721 with a maximum default of $2.55 million. Of all the defaults eight were based on collateral and four were based on payments. Six of the eight defaulting participants were financial companies. All of the credit defaults were promptly cured in the 2011 calendar year.[7] These defaults were not related to FTR positions.

- **Credit Rules Changes.** On September 15, 2011, the FERC conditionally approved PJM's proposed revisions to its credit policy filed in compliance with FERC's Order No. 741, which required tighter credit standards for all RTOs.[8]

  As a result of these new requirements, most PJM members complied with PJM's new minimum financial requirements effective October 1, 2011. Based on submitted information, 17 members did not meet the new requirements. Of these 17, 16 opted to reduce or discontinue their transaction activity and one did not comply, and was declared in default. These 17 members accounted for 0.1 percent of the aggregate bids in the 2011 to 2012 Annual FTR auction.[9]

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2011 to 2012 Annual FTR Auction was low for peak and off

6 OA Schedule 1 § 7.3.5(d).

7 Email to Members Committee, "PJM Settlement Member Credit Exposure – End of December 2011," January 12, 2012.

8 *PJM Interconnection, L.L.C.*, 136 FERC ¶61,190 (September 15th Order); *see also Credit Reforms in Organized Wholesale Electric Markets*, Order No. 741, FERC Stats. & Regs. ¶31,317 (2010), *order on reh'g*, Order No. 741-A, FERC Stats. & Regs. ¶31,320, *reh'g denied*, Order No. 741-B, 135 FERC ¶61,242 (2011).

9 It is not possible to evaluate the impact on members which members did not report.

peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was also low for peak and off peak FTR buy bid options and highly concentrated for 24-hour FTR buy bid options for the same time period. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

For the 2012 through 2015 Long Term FTR Auction, financial entities purchased 90 percent of prevailing flow FTRs and 94 percent of counter flow FTRs. In the Annual FTR Auction, planning period 2011 through 2012, financial entities purchased 56 percent of prevailing flow FTRs and 85 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 83 percent of prevailing flow and 90 percent of counter flow FTRs for the 2011 calendar year. Financial entities owned 51.5 percent of all prevailing and counter flow FTRs, including 45.8 percent of all prevailing flow FTRs and 68.3 percent of all counter flow FTRs during the same time period.

Market Performance

- **Volume.** The 2012 to 2015 Long Term FTR Auction cleared 259,885 MW (10.8 percent of demand) of FTR buy bids, compared to 238,681 MW (12.0 percent) in the 2011 to 2014 Long Term FTR Auction. The 2012 to 2015 Long Term FTR Auction also cleared 31,288 MW (12.5 percent) of FTR sell offers, up from 12,501 MW (7.0 percent) in the 2011 to 2012 Long Term FTR Auction.

  For the 2011 to 2012 planning period, the Annual FTR Auction cleared 341,726 MW (10.6 percent) of FTR buy bids, compared to 231,663 MW (13.6 percent) for the 2010 to 2011 planning period. The 2011 to 2012 Annual FTR Auction also cleared 24,960 MW (7.4 percent) of FTR sell offers for the 2011 to 2012 planning period, up from 10,315 MW (5.8 percent) for the 2010 to 2011 planning period.

  For the first seven months of the 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,589,990 MW (12.5 percent) of FTR buy bids and 427,443 MW (10.7 percent) of FTR sell offers.

- **Price.** In the 2012 to 2015 Long Term FTR Auction, more Long Term FTRs were purchased for less than $1 than in the prior Long Term Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction rose from -$0.16 to $0.36 per MW. Counter flow buy bid prices were negative, but greater in absolute value, than prevailing flow FTR bid prices.

  For the 2011 to 2012 Annual Auction, slightly fewer FTRs were purchased for less than $1 than in the prior Annual Auction. The weighted-average price for 24-hour buy bid obligations in the 2011 to 2012 planning period was $0.68 per MW, up from $0.43 in the 2010 to 2011 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 planning period was $0.13, down from $0.17 per MW in the first seven months of the 2010 to 2011 planning period.

- **Revenue.** The 2012 to 2015 Long Term FTR Auction generated $20.5 million of net revenue for all FTRs, down from $49.8 million in the 2011 to 2014 Long Term FTR Auction and the lowest net revenue since the Long Term FTR Auction's inception. This drop in net revenue is largely due to a 106.2 percent increase in revenue for sell offers from the 2011 to 2014 Long Term FTR Auction, along with a 29.5 percent drop in prevailing flow FTR buy bids.

  The 2011 2012 planning period Annual FTR Auction generated $1,029.7 million of net revenue for all FTRs, down from $1,049.8 million for the 2010 to 2011 planning period.

  The Monthly Balance of Planning Period FTR Auctions generated $21.9 million in net revenue for all FTRs for the first seven months of the 2011 to 2012 planning period, up from $16.7 million for the same time period in the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were paid at 85.0 percent of the target allocation for the 2010 to 2011 planning period. FTRs were paid at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $570.3 million of FTR revenues during the first seven months of the 2011 to 2012 planning period and $1,430.7 million during the 2010 to 2011 planning period. For the first seven months of the 2011 to 2012 planning period, the top sink and top source with the highest positive FTR target allocations were AEP without Mon Power and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were AEP without Mon Power and Kammer.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $340.3 million in profits for physical entities, of which $560.5 million was from self scheduled FTRs, and $125.7 million for financial entities. FTR profits generally increased in the summer and winter months when congestion was higher and decreased in the shoulder months when congestion was lower. As shown in Table 12-24, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self scheduled, were not profitable in 2011. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2011.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2011 to 2012 planning period were the South Mahwah – Waldwick line, in northern New Jersey, and the East Frankfort – Crete line, approximately 20 miles south of Chicago, IL. The geographic location of these constraints is shown in Figure 12-1. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.
- **Demand.** Total requested volume in the annual ARR allocation was 148,538 MW for the 2011 to 2012 planning period with 64,160 MW requested in Stage 1A, 22,208 MW requested in Stage 1B and 57,053 MW requested in Stage 2. This is up from 135,614 MW for the 2010 to 2011 planning period with 61,793 MW requested in Stage 1A, 37,850 MW requested in Stage 1B and 45,971 MW requested in Stage 2. The ATSI integration accounted for 5,434 MW of increased demand. The total ARR volume allocated is limited by the amount of network service and firm point-to-point transmission service.
- **ARR Reassignment for Retail Load Switching.** There were 24,531 MW of ARRs associated with approximately $388,700 of revenue that were reassigned in the first seven months of the 2011 to 2012 planning period. There were 56,296 MW of ARRs associated with approximately $1,043,700 of revenue that were reassigned for the full twelve months of the 2010 to 2011 planning period.

Market Performance

On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the 2011 to 2012 Annual ARR Allocation. For a transitional period, those customers that receive, and pay for, firm transmission service that sources or sinks in newly integrated PJM control zones may elect to receive a direct allocation of FTRs instead of an allocation of ARRs. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into PJM. In the 2011 to 2012 planning period 5,434 MW of ARRs were requested and 2,770 MW were allocated (51 percent) and 7,750 MW of directly allocated FTRs were requested while 4,189 MW were allocated (54 percent).

- **Volume.** Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. Market participants self scheduled 46,017 MW (44.9 percent) of these allocated ARRs as Annual FTRs. Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. Market participants self scheduled 55,732 MW (54.6 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** There are no ARR revenues. ARRs are allocated to qualifying customers because they pay for the transmission system.
- **Revenue Adequacy.** For the 2011 to 2012 planning period, the ARR target allocations were $947.3 million while PJM collected $1,051.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2011, making ARRs revenue adequate. For the 2010 to 2011 planning period, the ARR target allocations were $1,028.8 million while PJM collected $1,066.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARR Proration.** Stage 1A ARR requests may not be prorated. Some of the requested ARRs for the 2011 to 2012 planning period were prorated in Stage 1B and Stage 2 as a result of binding transmission constraints. For the 2010 to 2011 planning period, no ARRs were prorated in Stage 1B of the annual ARR allocation.
- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2010 to 2011 planning period, the total revenues received by ARR holders, including self scheduled FTRs, more than covered the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2010 to 2011 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 97.0 percent of the total congestion costs within PJM. During the first seven months of the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 100 percent of the total congestion costs within PJM.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service. FTR holders do not have the right to revenue adequacy.

PJM created the split between ARRs and FTRs in order to both continue to provide the appropriate protection against congestion for load, and to permit any excess transmission capacity on the system to be made available to those market participants who wished to use FTRs to speculate or to hedge positions. The FTR auctions provide market participants with the opportunity to hedge positions or to speculate and permits ARR holders to convert ARRs into FTRs. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2011 to 2012 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

Based on the FTR target allocations, there has been significant underfunding of FTRs since the spring of 2010. Underfunding or revenue inadequacy occurs when total congestion, which is comprised of day-ahead congestion plus balancing congestion, is less than the FTR target allocation. Total congestion revenues are allocated to FTR holders based on FTR target allocations.[10] FTRs were paid at 85.0 percent of the target allocation level for the 2010 to 2011 planning period. FTRs were paid at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period. Revenue adequacy for a planning period is not final until the end of the period. Underfunding and revenue inadequacy are misnomers because they appear to imply that the correct answer is that revenues must fully cover congestion on FTR paths, the target allocations. There is no guarantee of full revenue adequacy for FTRs. The mechanism that has the stated intent of assuring full revenue adequacy for FTRs is in fact a mechanism for self funding of revenue adequacy. FTR holders themselves make up any

10 PJM Financial Transmission Rights Task Force (FTRTF), <http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>.

shortfall. Rather than a revenue adequacy mechanism, this is a mechanism to ensure that revenue shortfalls on specific transmission paths are socialized among all FTR holders and that all FTR holders share in the shortfall proportionately.

PJM is attempting to meet two competing objectives in determining the level of FTRs to offer in FTR auctions. Funding FTRs is a valid objective. Maximizing the efficient usage of the transmission system by increasing the level of offered FTRs is also a valid objective. FTR underfunding reflects PJM's efforts to balance competing objectives. FTR revenue shortfalls are not evidence that there is any deficiency with PJM's approach. PJM could effectively guarantee full funding of FTRs by using more conservative assumptions in its auction model. But that would inappropriately tilt toward one end of the tradeoff between revenue sufficiency and maximizing the availability of FTRs. It is not clear whether there would be any revenue shortfalls if PJM had not created separate ARR and FTR products but had continued to assign FTRs based on the purchase of transmission service.

The reasons for recent increased shortfalls in FTR funding, identified by PJM, support the continued use of the current definition of FTR revenues, which includes balancing congestion. The reasons offered by PJM are reduced transmission capability and the difficulty of modeling Midwest Independent System Operator, Inc. ("MISO") flowgates in the FTR Auction model. These both result in over selling FTRs. Over selling FTRs creates balancing congestion, which reduces the funds available to pay FTR holders. It is appropriate that FTR holders are paid less when FTR revenues, including balancing congestion, are reduced.

Both of the cited reasons resulted in PJM selling more FTR capability in the FTR auctions than exists. This was a result of the fact that FTR auctions are run well before the time that congestion is experienced and reality does not always match the model used in the auction to define available FTRs. The difficulty in predicting flows on PJM/MISO flowgates used in market-to-market congestion management and the reduction in overall transmission capability in turn results in differences between day-ahead models and actual experience in real time.

FTR holders do not have guarantees from PJM or PJM transmission customers that their payments would depend on modeling assumptions in the day-ahead market rather than total congestion. FTR holders cannot reasonably expect that such payments would ignore balancing congestion. It would be inappropriate to have FTR holders' revenues depend solely on modeling assumptions rather than on actual total congestion, including balancing congestion.

Underfunding is a logical consequence of overselling FTRs. When FTRs are oversold, a decline in their value can be expected. A reduction in FTR revenue sufficiency is a market signal and a correct market signal. The level of FTRs sold reflects PJM's judgment. The logical conclusion is not that underfunding must be eliminated through a change in the funding mechanism but that it is an expected consequence of the ongoing transmission upgrades on the system, the unanticipated level of congestion on MISO flowgates, and PJM's choices about the level of FTRs sold. If full funding is the goal, fewer FTRs should be sold, reflecting the reduced capability of the transmission system.

The notion that underfunding is a problem that should be solved through external subsidies depends on the assertion that FTR holders are guaranteed payments based on the definition of target allocations. Target allocations serve as a cap on FTR payments by time period and therefore define the amount of over collections that are spread to other periods. Target allocations do not establish an entitlement to any level of funding. FTR holders are not entitled to such a guarantee backed by an allocation of shortfalls to all transmission customers. FTR holders do not have a reasonable expectation of funding at that level. The valuation of FTRs by purchasers includes market risk. Market participants appropriately bear this risk and they should not be permitted to shift those risks to others. FTR holders are in position to assess the value of the FTRs that they purchase. If they are wrong, they appropriately bear the risks. It is a fundamental precept of market design that market participants should bear the risks associated with their decisions. External subsidies should not be introduced in order to attenuate that link. That would distort incentives and correspondingly distort market decisions.

The value of FTRs is determined by the revenue available to fund them. The value of FTRs is not determined by the target allocation. FTRs are financial products which serve a number of market functions from hedging to speculation. FTRs are voluntarily purchased in the market.

It has been suggested by some market participants that balancing congestion should be paid by all transmission customers, regardless of ARR allocations. But it has not been explained why transmission customers who did not purchase FTRs should play a role in funding FTRs by absorbing balancing congestion. Nor has it been explained why creating another unavoidable uplift charge with no causal link to those paying it is superior to continuing to have the market value FTRs, and have FTR purchasers make rational decisions about how much to pay for FTRs based on expectations about available congestion revenues. The current approach results in an appropriate match between the decision maker and the result. The introduction of a subsidy financed through an uplift charge would disrupt the link between the decision maker and the result.

Until the fundamental issues underlying FTR funding can be addressed, that level of revenue sufficiency will continue to be a correct market signal. FTR holders can pay less for FTRs if they believe that their value has been reduced, or PJM can make fewer FTRs available. These are very similar outcomes.

PJM and its stakeholders identified discrepancies between auction modeling and actual system conditions as the primary drivers of the underfunding. These discrepancies included outages not modeled in the annual or monthly auctions and additional transmission switching decisions not incorporated in the model. The impact of including balancing congestion in the calculation of revenues was also noted.[11] Although the annual FTR auction represents the entire year, the auction model reflects the PJM system for a single point in time. PJM must evaluate transmission line outage schedules and thermal operating limits for transmission lines for inclusion in the model for the Annual FTR Auction. FTR revenue adequacy is not guaranteed nor should it be. PJM should model the system as accurately as possible and participants should bid prices that reflect their evaluations of the expected profitability of FTRs.

The MMU recommends that a detailed review of the ARR/FTR allocation and market clearing be conducted in order to better understand and address the reasons for FTR underfunding. This review should include the assumptions made in the modeling of auctions and their basis in market developments. The MMU also recommends an explicit statement in the rules explaining the purpose and objectives of ARRs, FTRs and the appropriate level of funding of FTRs. The MMU recommends that no action to substantially modify the market design, e.g. removal of balancing congestion from the calculation of FTR revenues, be taken until the review is complete.

For the 2010 to 2011 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 97.0 percent of the total congestion costs within PJM. During the first seven months of the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 100 percent of the total congestion costs within PJM. The ARR and FTR revenue offset results are aggregate results and all those paying congestion charges did not necessarily receive that level of offset. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

The MMU also recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. Positively valued ARRs follow load when load switches between suppliers. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

11 The Market Implementation Committee (MIC) approved the creation of the Financial Transmission Rights Task Force (FTRTF) to investigate the causes of the FTR revenue inadequacy that occurred in the 2010 to 2011 Planning Period and identify potential improvements that could be made to minimize the revenue inadequacy going forward.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. Since the 2006 to 2007 planning period, the auction has covered all control zones.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[12] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation is a cap on what FTR holders can receive. Revenues above that level are used to fund FTRs which received less than their target allocations.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. Revenues to fund FTRs come from both day-ahead congestion charges on the transmission system and balancing congestion charges. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs, and only in the Annual FTR Auction.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

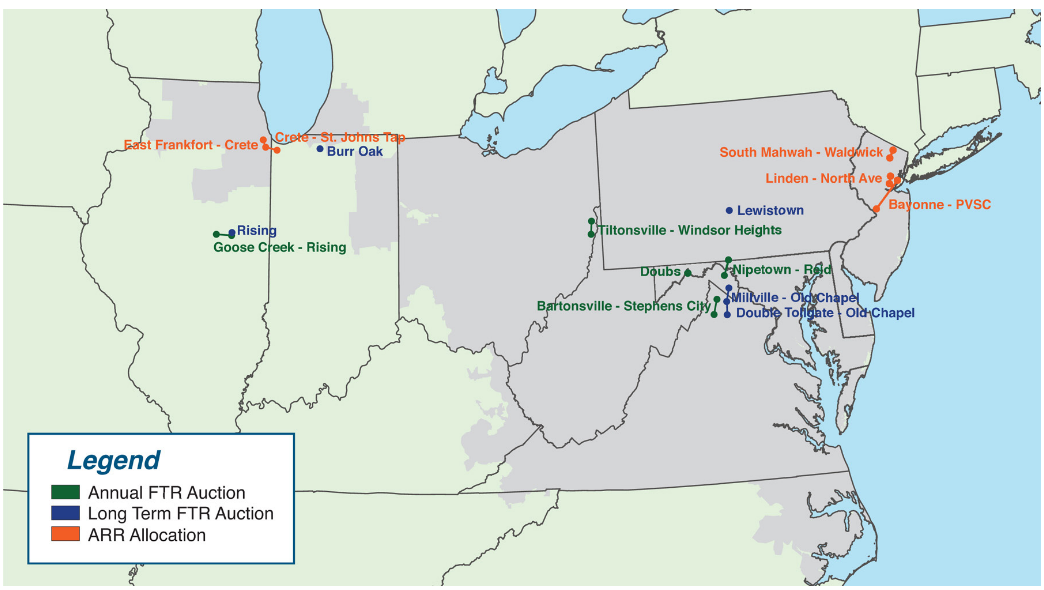
12 For additional information on marginal losses, see the *2011 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[13] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[14] But the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration which do not overlap in time. The choice of which to model may have distributional consequences.

During the 2011 to 2012 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[15] Table 12-2 and Table 12-3 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[16] Table 12-2 and Table 12-3 demonstrate the marginal value for on peak hours only. The top five binding transmission constraints for the Long Term FTR Auction and the Annual FTR Auction can be seen in Figure 12-1.

Figure 12-1 Geographic location of top five binding constraints for the Long Term and Annual FTR Auctions and ARR allocations: Planning periods 2012 to 2015 and 2011 to 2012



13 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.
14 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.
15 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM website in monthly files at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx>.
16 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.

Table 12-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2012 to 2015

Constraint	Type	Control Zone	Severity Ranking by Auction Round 1	2	3
Millville - Old Chapel	Line	AP	NA	1	NA
Burr Oak	Flowgate	MISO	NA	2	8
Lewistown	Transformer	PENELEC	NA	NA	1
Double Tollgate - Old Chapel	Line	AP	1	5	13
Rising	Flowgate	MISO	NA	NA	2
Belmont	Transformer	AP	2	3	6
Bartonsville - Stephens City	Line	AP	3	NA	NA
31st Street - Westfall	Line	PENELEC	NA	NA	3
Clinton - Findlay	Line	DLCO	NA	NA	4
Roxbury - Shade Gap	Line	PENELEC	7	4	NA

Table 12-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2011 to 2012

Constraint	Type	Control Zone	Severity Ranking by Auction Round 1	2	3	4
Doubs	Transformer	AP	NA	1	1	1
Bartonsville - Stephens City	Line	AP	NA	2	NA	NA
Goose Creek - Rising	Flowgate	MISO	NA	4	2	2
Tiltonsville - Windsor	Line	AP	43	5	4	3
Nipetown - Reid	Line	AP	NA	3	3	4
Bedington - Harmony	Line	AP	NA	6	5	5
Palisades - Cook	Flowgate	MISO	NA	9	12	14
Mahans Lane - Tidd	Line	AEP	3	7	7	6
Belmont	Transformer	AP	NA	8	8	7
Wolfcreek	Transformer	AEP	NA	10	10	11

Long Term FTR Auction

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[17] The 2011 to 2014 and 2012 to 2015 Long Term FTR Auctions consisted of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one year or a single term of all three years.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.
- **Round 2.** The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- **Round 3.** The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction in which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding FTRs approved in prior Long Term FTR Auctions. If participants wish to self schedule ARRs as FTRs, it must be done in the first round of the Annual FTR Auction. Self scheduled FTRs must have the same source and sink as the corresponding ARR. Self scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price. The auction takes place over four rounds with 25 percent of the feasible transmission system capability awarded in each round:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[18] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self scheduled FTRs must do so in this round. One quarter of each self scheduled FTR clears as a 24-hour FTR in each of the four rounds.

17 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

18 Long Term, Annual and Monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives offsetting revenue for the ARR and is left with the FTR and any revenues associated with it.

The following is an example of self scheduling ARRs as FTRs. An ARR holder receives an allocation of 1 MW from source A to sink B. The ARR holder self schedules the ARR as an FTR in the Annual FTR Auction. The price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR and receives a $100 ARR target credit based on the ARR. In addition, the ARR holder obtains the corresponding FTR.

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system after the Long Term and Annual FTR Auctions are concluded is offered in the Monthly Balance of Planning Period FTR Auctions. These are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak or off peak products.19

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Buy Bids

In the 2012 to 2015 Long Term FTR Auction, total FTR buy bids increased 1.3 percent from 400,222 MW to 405,504 MW. In the Annual FTR Auction total FTR buy bids and self scheduled bids increased 84.8 percent from 1,764,288 MW to 3,260,695 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 planning period increased 42.3 percent from 8,973,645 MW, during the same time period of the prior planning period, to 12,767,075 MW.

Limits on Number of Bids

The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a single round of an annual auction, if necessary to avoid system performance issues.[20] PJM has previously limited the maximum number of bids per participant to 20,000 bids. Effective with the September 2011 Monthly Balance of Planning Period FTR Auction, PJM reduced the maximum number of bids per participant to 10,000 bids for any FTR auction. For example, a participant in the September 2011 Monthly Balance of Planning Period FTR Auction could place 10,000 bids for each of the six periods of September, October, November, Q2, Q3 and Q4 for a total of 60,000 bids. PJM indicated that this reduction was required for reasons of system performance.[21] This rule change affected only a small number of participants. The number of unique participants in the Annual FTR Auction has increased

19 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

20 OA Schedule 1 § 7.3.5(d).

21 See Messages section in eFTR within the PJM eSuite application <https://esuite.pjm.com/mui/> (Accessed November 4, 2011).

from 74, in the 2003 to 2004 planning period, to 272 in the 2011 to 2012 planning period, and the average MW bid has decreased from its peak of 29 MW per participant in the 2004 to 2005 planning period to 14 MW per bid in the 2011 to 2012 planning period.

Credit Issues

Default

There were eight participants that defaulted during the 2011 calendar year and 12 default events. The average default for the 2011 calendar year was $282,721 with a maximum default of $2.55 million. Of all the defaults eight were based on collateral and four were based on payments. Six of the eight defaulting participants were financial companies. All of the credit defaults were promptly cured in the 2011 calendar year.[22] These defaults were not related to FTR positions.

Credit Rules

Following a series of high profile defaults, PJM made significant reforms to its credit policies in 2007–2009.[23] On September 15, 2011, the FERC conditionally approved PJM's proposed revisions to its credit policy filed in compliance with FERC's Order No. 741, which required tighter credit standards for all RTOs.[24] The FERC determined that PJM was already compliant in a number of respects, and, effective October 1, 2011, permitted PJM to implement the following changes: the maximum aggregate unsecured limit for affiliated groups was reduced to $50 million from $150 million; minimum financial criteria for participation in PJM market; and PJM is now required to explain in writing application of its Material Adverse Change provisions.[25]

On November 29, 2011, PJM submitted in compliance with the September 15th Order revisions (i) verifying compliance with minimum criteria for market participation (ii) modifying the officer certification form to clarify attestations about the nature of the participant's trading activity and (iii) eliminating reliance on seller credit in FTR markets (and capping seller credit for other purposes).[26] The filing also revised the Certification Form to indicate that the signatory acknowledges that the information provided in the certificate is true and accurate to the best of the signatory's belief and knowledge after due investigation.[27]

PJM requested an effective date of December 13, 2011. Approval of the compliance filing, and requests for rehearing of the September 15th Order, are now pending at the FERC. The elimination of seller credit from FTR markets, which would eliminate reliance on unsecured credit consistent with the recommendation included in prior state of the market reports, is among the issues pending on rehearing.[28]

PJM stated that it will require submittal of officer certification forms and risk management procedures during the first four months of 2012.[29]

Smaller financial traders had asserted that the new requirements may exclude them from the markets and negatively impact liquidity.[30] As a result of these new requirements, most PJM members complied with PJM's new minimum financial requirements effective October 1, 2011. Based on submitted information, 17 members did not meet the new requirements. Of these 17, 16 opted to reduce or discontinue their transaction activity and one did not comply, and was declared in default. These 17 members accounted for 0.1 percent of the aggregate bids in the 2011 to 2012 Annual FTR auction.[31]

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

22 Email to Members Committee, "PJM Settlement Member Credit Exposure – End of December 2011," January 12, 2012.

23 See 127 FERC ¶ 61,017 (2009).

24 *PJM Interconnection, L.L.C.*, 136 FERC ¶61,190 (September 15th Order); *see also Credit Reforms in Organized Wholesale Electric Markets*, Order No. 741, FERC Stats. & Regs. ¶31,317 (2010), *order on reh'g*, Order No. 741-A, FERC Stats. & Regs. ¶31,320, *reh'g denied*, Order No. 741-B, 135 FERC ¶61,242 (2011).

25 *Id.*

26 Transmittal Letter for Compliance Filing of PJM in Docket No. ER11-3972-002 at 4.

27 *Id.*

28 *See, e.g.*, Request for Rehearing, Clarification, and Technical Conference of Electric Power Supply Association filed in Docket No. ER11-3972-001 (October 17, 2011).

29 Email from Suzanne Daugherty, PJM Vice President and CFO to Members, "Summary of FERC Order on PJM's Credit Order 741 Compliance Filing" (September 16, 2011) ("PJM Email Summary").

30 *See* FERC Docket No. ER11-3972.

31 It is not possible to evaluate the impact on members which members did not report.

The ownership concentration of cleared FTR buy bids resulting from the 2011 to 2012 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options.

For cleared FTR buy-bid obligations in the 2011 to 2012 Annual FTR Auction, the HHIs were 1036 for 24-hour, 549 for on peak and 655 for off peak FTR products while maximum market shares were 16.6 percent for 24-hour, which is associated with a physical entity, 11.4 percent for on peak, which is associated with a financial entity, and 11.4 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2011 to 2012 Annual FTR Auction, HHIs were 4542 for 24-hour, 824 for on peak and 886 for off peak products while maximum market shares were 62.9 percent for 24-hour, which is associated with a physical entity, 16.4 percent for on peak, which is associated with a financial entity, and 14.7 percent for off peak FTR products, which is associated with a financial entity.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 12-4 presents the 2012 to 2015 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities own 89.9 percent of prevailing flow cleared buy bid FTRs and 94.2 percent of counter flow cleared buy bid FTRs. Overall, financial entities own about 91.8 percent of all Long Term Auction cleared buy bid FTRs.

Table 12-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2012 to 2015[32]

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	10.2%	5.8%	8.2%
	Financial	89.8%	94.2%	91.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	7.9%	5.4%	7.3%
	Financial	92.1%	94.6%	92.7%
	Total	100.0%	100.0%	100.0%

Table 12-5 presents the Annual FTR Auction market cleared FTRs in the 2011 to 2012 planning period by trade type, organization type and FTR direction, including self scheduled FTRs. The results show that physical entities own 43.9 percent of prevailing flow cleared buy bid FTRs while financial entities own 84.8 percent of counter flow cleared buy bid FTRs. In the 2011 to 2012 Annual FTR Auction physical entities own 9.5 percent of all sold FTRs while financial entities own 90.5 percent of all sold FTRs.

Table 12-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2011 to 2012

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	17.2%	1.0%	11.9%
		No	26.7%	14.2%	22.6%
		Total	43.9%	15.2%	34.4%
	Financial	No	56.1%	84.8%	65.6%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		9.5%	9.8%	9.5%
	Financial		90.5%	90.2%	90.5%
	Total		100.0%	100.0%	100.0%

Table 12-6 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs in calendar year 2011 by trade type, organization type and FTR direction. The results show that physical entities own only 9.9 percent of counter flow cleared buy bid FTRs while financial entities own 90.1 percent. Overall, financial entities own 86.7 percent of all Monthly Balance of Planning Period cleared buy bid FTRs.

32 Table 12-4, Table 12-5 and Table 12-6 are updated from *2009 State of the Market Report* to include trade type. Previous versions of these tables netted the buy and sell MW by FTR and organization. This created organizations with FTRs that had a net negative MW volume in the respective auction.

Table 12-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2011

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	16.7%	9.9%	13.3%
	Financial	83.3%	90.1%	86.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	28.8%	12.3%	24.8%
	Financial	71.2%	87.7%	75.2%
	Total	100.0%	100.0%	100.0%

Table 12-7 presents the daily FTR net position ownership in 2011 by FTR direction. To determine the daily FTR net position for an organization, the net position of all FTRs, including all auctions, is calculated for every organization each day. An organization's net daily position is the difference between all FTR buys and FTR sells from all relevant auctions and bilateral trades for each day. The net position of all FTRs, including all auctions, is calculated for every organization each day. The data is summarized for the 2011 calendar year to show the ownership patterns by FTR direction. Physical entities owned 40.4 percent of all prevailing flow FTRs and 22.2 percent of counter flow FTRs in 2011.

Table 12-7 Daily FTR net position ownership by FTR direction: Calendar year 2011

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	40.4%	22.2%	35.4%
Financial	59.6%	77.8%	64.6%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 12-8 shows the 2012 to 2015 Long Term FTR Auction volume by trade type, FTR direction and period type.[33] The total volume was 2,400,881 MW for FTR buy bids and 251,290 MW for FTR sell offers in the 2012 to 2015 Long Term FTR Auction. This is up from the total volume of 1,996,084 MW for FTR buy bids and 117,540 MW for FTR sell offers in the 2011 to 2014 Long Term FTR Auction.

The 2012 to 2015 Long Term FTR Auction cleared 259,885 MW (10.8 percent of demand) of FTR buy bids, compared to 238,681 MW (12.0 percent) in the 2011 to 2014 Long Term FTR Auction. The 2012 to 2015 Long Term FTR Auction also cleared 31,288 MW (12.5 percent) of FTR sell offers, up from 12,501 MW (7.0 percent) in the 2011 to 2012 Long Term FTR Auction.

The volume of buy bids for the period covering all three years of the Long Term Auction was only 830 MW, with none clearing the auction.

In the 2012 to 2015 Long Term FTR Auction, there were 123,381 MW (30.8 percent) cleared counter flow FTR buy bids and 136,504 MW (6.8 percent) cleared prevailing flow FTR buy bids. In the 2012 to 2015 Long Term FTR Auction, there were 6,746 MW (8.2 percent) cleared counter flow FTR sell offers and 24,543 MW (14.6 percent) cleared prevailing flow FTR sell offers.

Table 12-9 shows the Annual FTR Auction volume by trade type, hedge type and FTR direction for the 2011 to 2012 planning period. The total volume was 3,214,678 MW for FTR buy bids and 337,510 MW for FTR sell offers for the 2011 to 2012 planning period. This is up from the total volume of 1,708,556 MW for FTR buy bids and up from 178,428 MW for FTR sell offers for the 2010 to 2011 planning period.

There were 341,726 MW (10.6 percent) of cleared FTR buy bids and 24,960 MW (7.4 percent) of cleared FTR sell offers for the 2011 to 2012 planning period. This is up from the total of 231,663 MW (13.6 percent) of cleared FTR buy bids and up from 10,315 MW (5.8 percent) of cleared FTR sell offers for the 2010 to 2011 planning period.

For the 2011 to 2012 planning period, there were 126,654 MW (30.3 percent) counter flow FTR buy bids and 215,071 MW (7.7 percent) cleared prevailing flow FTR buy bids. During the 2011 to 2012 planning period, there were 4,676 MW (3.6 percent) cleared counter flow FTR sell offers and 20,284 MW (9.8 percent) cleared prevailing flow FTR offers.

33 Calculated values shown in Section 12, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 12-8 Long Term FTR Auction market volume: Planning periods 2012 to 2015

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	35,974	148,674	45,589	30.7%	103,085	69.3%
		Year 2	26,884	124,784	37,622	30.2%	87,162	69.8%
		Year 3	26,605	127,166	40,169	31.6%	86,997	68.4%
		Year All	12	384	0	0.0%	384	100.0%
		Total	89,475	401,008	123,381	30.8%	277,628	69.2%
	Prevailing Flow	Year 1	129,341	773,818	53,934	7.0%	719,884	93.0%
		Year 2	98,027	623,153	41,074	6.6%	582,079	93.4%
		Year 3	88,639	602,455	41,497	6.9%	560,959	93.1%
		Year All	22	446	0	0.0%	446	100.0%
		Total	316,029	1,999,873	136,504	6.8%	1,863,368	93.2%
	Total		405,504	2,400,881	259,885	10.8%	2,140,996	89.2%
Sell offers	Counter Flow	Year 1	13,034	44,098	3,088	7.0%	41,010	93.0%
		Year 2	8,441	28,365	2,502	8.8%	25,863	91.2%
		Year 3	2,595	10,265	1,155	11.2%	9,111	88.8%
		Year All	NA	NA	NA	NA	NA	NA
		Total	24,070	82,729	6,746	8.2%	75,983	91.8%
	Prevailing Flow	Year 1	21,009	86,831	14,079	16.2%	72,752	83.8%
		Year 2	15,598	67,105	8,745	13.0%	58,360	87.0%
		Year 3	4,178	14,625	1,718	11.7%	12,907	88.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	40,785	168,561	24,543	14.6%	144,019	85.4%
	Total		64,855	251,290	31,288	12.5%	220,002	87.5%

Table 12-9 Annual FTR Auction market volume: Planning period 2011 to 2012

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	92,575	401,779	116,108	28.9%	285,671	71.1%
		Prevailing Flow	282,198	1,688,422	176,164	10.4%	1,512,258	89.6%
		Total	374,773	2,090,201	292,273	14.0%	1,797,928	86.0%
	Options	Counter Flow	194	15,546	10,546	67.8%	5,000	32.2%
		Prevailing Flow	30,420	1,108,931	38,907	3.5%	1,070,024	96.5%
		Total	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
	Total	Counter Flow	92,769	417,325	126,654	30.3%	290,671	69.7%
		Prevailing Flow	312,618	2,797,353	215,071	7.7%	2,582,282	92.3%
		Total	405,387	3,214,678	341,726	10.6%	2,872,952	89.4%
Self-scheduled bids	Obligations	Counter Flow	249	1,278	1,278	100.0%	0	0.0%
		Prevailing Flow	10,163	44,739	44,739	100.0%	0	0.0%
		Total	10,412	46,017	46,017	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	92,824	403,057	117,386	29.1%	285,671	70.9%
		Prevailing Flow	292,361	1,733,161	220,903	12.7%	1,512,258	87.3%
		Total	385,185	2,136,218	338,290	15.8%	1,797,928	84.2%
	Options	Counter Flow	194	15,546	10,546	67.8%	5,000	32.2%
		Prevailing Flow	30,420	1,108,931	38,907	3.5%	1,070,024	96.5%
		Total	30,614	1,124,477	49,453	4.4%	1,075,024	95.6%
	Total	Counter Flow	93,018	418,603	127,932	30.6%	290,671	69.4%
		Prevailing Flow	322,781	2,842,092	259,810	9.1%	2,582,282	90.9%
		Total	415,799	3,260,695	387,743	11.9%	2,872,952	88.1%
Sell offers	Obligations	Counter Flow	29,939	123,127	4,676	3.8%	118,451	96.2%
		Prevailing Flow	46,211	196,244	20,118	10.3%	176,126	89.7%
		Total	76,150	319,371	24,794	7.8%	294,577	92.2%
	Options	Counter Flow	40	7,820	0	0.0%	7,820	100.0%
		Prevailing Flow	783	10,319	166	1.6%	10,153	98.4%
		Total	823	18,139	166	0.9%	17,973	99.1%
	Total	Counter Flow	29,979	130,947	4,676	3.6%	126,271	96.4%
		Prevailing Flow	46,994	206,562	20,284	9.8%	186,279	90.2%
		Total	76,973	337,510	24,960	7.4%	312,550	92.6%

Table 12-10 shows that for the 2011 to 2012 planning period, eligible market participants self scheduled 46,017 MW of ARRs out of a possible 103,735 MW as Annual FTRs. In comparison, during the 2010 to 2011 planning period, eligible market participants self scheduled 55,732 MW of ARRs out of a possible 102,046 MW.

Table 12-10 Comparison of self scheduled FTRs: Planning periods 2009 to 2010, 2010 to 2011 and 2011 to 2012[34]

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%

Table 12-11 shows that there were 10,999,601 MW of FTR buy bid obligations and 3,504,363 MW of FTR sell offer obligations for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 planning period through December 31, 2011. The monthly auctions cleared 1,543,888 MW (14.0 percent) of FTR buy bid obligations and 314,027 MW (9.0 percent) of cleared FTR sell offer obligations.

There were 1,767,474 MW of FTR buy bid options and 480,419 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 planning period through December 31, 2011. The monthly auctions cleared 46,102 MW (2.6 percent) of FTR buy bid options. There were 113,416 MW (23.6 percent) of cleared FTR sell offer options.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2010 to 2011 planning period had a total demand of 14,291,535 MW for FTR buy bids, up from 8,219,996 MW for the 12-month 2009 to 2010 planning period, and 4,017,267 MW for FTR sell offers, up from 2,795,964 MW for the 12-month 2009 to 2010 planning period. The monthly auctions cleared 2,043,159 MW (14.3 percent) of FTR buy bids and 458,938 MW (11.4 percent) of FTR sell offers. Of the cleared buy bids for the 2010 to 2011 planning period, 1,975,624 MW (96.7 percent) were obligations. For cleared sell offers in the 2010 to 2011 planning period, 311,688 MW (67.9 percent) were obligations.

Table 12-12 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2011 through December 2011.

Figure 12-2 shows the cleared volume of buy and sell bids for each FTR Auction type as a percentage of total FTR volume in a calendar month. Annual and Long Term FTR Auctions contribute a constant volume for the planning period to each calendar month's total volume for their respective planning periods. Long Term FTR Auctions are broken into the appropriate planning periods depending on the period indicated in the bid. For example, a bid for the second year in the 2009 to 2013 Long Term FTR Auction applies only to each calendar month in the 2010 to 2011 planning period. Figure 12-2 shows that the cleared volume in the Annual FTR Auction has been steadily decreasing while the cleared volume from the Monthly Balance of Planning Period Auctions has been increasing.

Figure 12-2 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2011

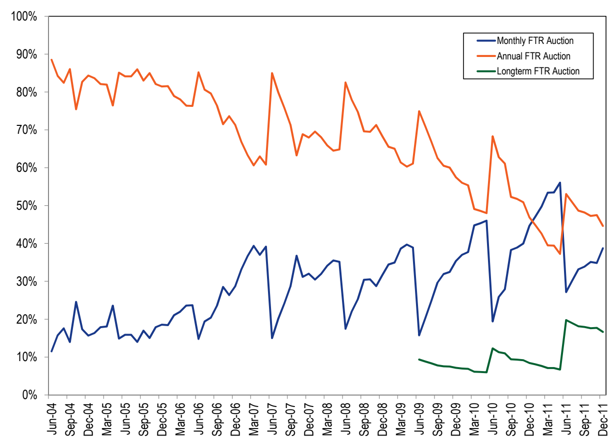


Table 12-13 shows the PJM secondary bilateral FTR market volume by hedge type and class type for the 2010 to 2011 and the 2011 to 2012 planning periods. There were 22,611 MW of total bilateral FTR activity for the 2011 to 2012 planning period through December 31, 2011, while there were 24,054 MW during the 2010 to 2011 planning period. Price data is not meaningful as PJM market participants enter zero as the price for more than 63 percent of secondary bilateral FTR transactions.

34 The column Maximum Possible Self-Scheduled FTRs in Table 12-4 is updated from the *2009 State of the Market Report* to include RTEP IARR MW. RTEP IARRs and ARRs can be self-scheduled in round 1 of the Annual FTR Auction.

Table 12-11 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2011

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-11	Obligations	Buy bids	189,084	1,101,808	164,743	15.0%	937,065	85.0%
		Sell offers	50,981	261,888	28,189	10.8%	233,699	89.2%
	Options	Buy bids	1,040	105,293	8,691	8.3%	96,602	91.7%
		Sell offers	2,927	43,161	12,380	28.7%	30,781	71.3%
Feb-11	Obligations	Buy bids	185,625	1,090,475	181,977	16.7%	908,497	83.3%
		Sell offers	41,609	220,079	20,957	9.5%	199,122	90.5%
	Options	Buy bids	959	93,909	9,372	10.0%	84,537	90.0%
		Sell offers	2,555	33,140	9,643	29.1%	23,497	70.9%
Mar-11	Obligations	Buy bids	192,349	1,154,132	216,165	18.7%	937,967	81.3%
		Sell offers	48,727	256,121	30,492	11.9%	225,629	88.1%
	Options	Buy bids	1,026	96,152	7,254	7.5%	88,898	92.5%
		Sell offers	2,351	41,200	10,587	25.7%	30,613	74.3%
Apr-11	Obligations	Buy bids	149,735	847,575	164,278	19.4%	683,297	80.6%
		Sell offers	37,737	220,966	22,108	10.0%	198,858	90.0%
	Options	Buy bids	919	66,008	5,387	8.2%	60,621	91.8%
		Sell offers	1,834	32,136	9,327	29.0%	22,810	71.0%
May-11	Obligations	Buy bids	138,353	741,926	189,851	25.6%	552,075	74.4%
		Sell offers	27,642	122,217	13,661	11.2%	108,556	88.8%
	Options	Buy bids	759	20,612	2,485	12.1%	18,127	87.9%
		Sell offers	1,184	19,631	9,065	46.2%	10,566	53.8%
Jun-11	Obligations	Buy bids	332,116	1,924,420	312,144	16.2%	1,612,276	83.8%
		Sell offers	135,073	585,528	40,839	7.0%	544,689	93.0%
	Options	Buy bids	7,625	256,153	11,013	4.3%	245,140	95.7%
		Sell offers	18,794	103,002	24,097	23.4%	78,904	76.6%
Jul-11	Obligations	Buy bids	343,986	2,085,575	286,143	13.7%	1,799,432	86.3%
		Sell offers	124,629	554,483	37,933	6.8%	516,549	93.2%
	Options	Buy bids	3,239	147,732	13,337	9.0%	134,395	91.0%
		Sell offers	12,897	76,029	20,259	26.6%	55,770	73.4%
Aug-11	Obligations	Buy bids	310,562	1,830,992	252,468	13.8%	1,578,524	86.2%
		Sell offers	117,597	529,879	40,335	7.6%	489,545	92.4%
	Options	Buy bids	3,070	150,896	6,736	4.5%	144,160	95.5%
		Sell offers	10,680	66,968	14,427	21.5%	52,541	78.5%
Sep-11	Obligations	Buy bids	255,744	1,352,484	180,231	13.3%	1,172,252	86.7%
		Sell offers	111,846	538,916	54,686	10.1%	484,230	89.9%
	Options	Buy bids	3,368	228,757	4,942	2.2%	223,815	97.8%
		Sell offers	10,816	73,140	17,741	24.3%	55,399	75.7%
Oct-11	Obligations	Buy bids	277,059	1,492,587	188,474	12.6%	1,304,113	87.4%
		Sell offers	91,184	430,188	46,727	10.9%	383,461	89.1%
	Options	Buy bids	3,342	416,369	4,336	1.0%	412,033	99.0%
		Sell offers	9,610	54,706	11,430	20.9%	43,276	79.1%
Nov-11	Obligations	Buy bids	245,707	1,254,959	170,134	13.6%	1,084,825	86.4%
		Sell offers	86,993	414,939	43,839	10.6%	371,101	89.4%
	Options	Buy bids	2,963	307,806	3,325	1.1%	304,481	98.9%
		Sell offers	7,571	49,692	11,915	24.0%	37,777	76.0%
Dec-11	Obligations	Buy bids	200,071	1,058,585	154,294	14.6%	904,292	85.4%
		Sell offers	94,062	450,429	49,668	11.0%	400,762	89.0%
	Options	Buy bids	3,401	259,762	2,413	0.9%	257,349	99.1%
		Sell offers	6,760	56,882	13,547	23.8%	43,335	76.2%
2010/2011*	Obligations	Buy bids	2,378,154	12,888,263	1,975,624	15.3%	10,912,639	84.7%
		Sell offers	709,605	3,448,995	311,688	9.0%	3,137,308	91.0%
	Options	Buy bids	16,090	1,403,272	67,536	4.8%	1,335,736	95.2%
		Sell offers	60,091	568,271	147,251	25.9%	421,021	74.1%
2011/2012**	Obligations	Buy bids	1,965,245	10,999,601	1,543,888	14.0%	9,455,713	86.0%
		Sell offers	761,384	3,504,363	314,027	9.0%	3,190,336	91.0%
	Options	Buy bids	27,008	1,767,474	46,102	2.6%	1,721,372	97.4%
		Sell offers	77,128	480,419	113,416	23.6%	367,003	76.4%

* Shows Twelve Months for 2010/2011; ** Shows seven months ended 31-Dec-2011 for 2011/2012

Table 12-12 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2011

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	Bid	677,552	197,260	140,265				192,024	1,207,101
	Cleared	134,232	18,200	8,548				12,454	173,434
Feb-11	Bid	705,015	157,482	139,776				182,111	1,184,383
	Cleared	156,562	11,243	11,107				12,438	191,350
Mar-11	Bid	774,291	206,225	205,539				64,228	1,250,283
	Cleared	173,607	22,830	20,602				6,380	223,419
Apr-11	Bid	698,577	215,007						913,583
	Cleared	153,834	15,832						169,666
May-11	Bid	762,538							762,538
	Cleared	192,336							192,336
Jun-11	Bid	893,961	247,465	245,244	87,002	241,008	219,128	246,765	2,180,573
	Cleared	176,087	28,040	27,497	10,733	28,673	26,805	25,321	323,157
Jul-11	Bid	924,620	300,178	148,980		293,107	287,862	278,560	2,233,307
	Cleared	171,384	28,868	14,197		27,365	31,676	25,990	299,480
Aug-11	Bid	892,507	181,881	169,691		238,458	248,517	250,833	1,981,888
	Cleared	168,550	16,915	15,175		15,479	20,858	22,227	259,204
Sep-11	Bid	743,395	186,272	182,067		49,451	206,242	213,814	1,581,240
	Cleared	120,684	16,207	15,317		3,983	14,362	14,621	185,173
Oct-11	Bid	862,809	266,426	252,455			256,279	270,987	1,908,956
	Cleared	127,312	19,605	13,087			15,121	17,684	192,810
Nov-11	Bid	670,097	236,522	210,716			202,931	242,498	1,562,764
	Cleared	114,996	16,860	14,371			10,256	16,977	173,459
Dec-11	Bid	611,433	237,942	222,675			24,799	221,498	1,318,347
	Cleared	116,390	14,930	13,254			1,637	10,495	156,707

Table 12-13 Secondary bilateral FTR market volume: Planning periods 2010 to 2011 and 2011 to 2012[35]

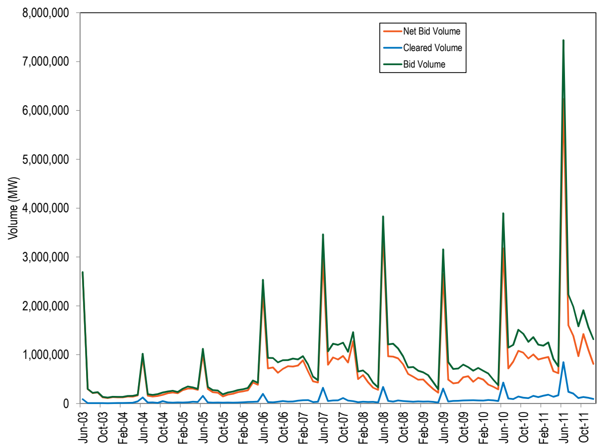
Planning Period	Hedge Type	Class Type	Volume (MW)
2010/2011	Obligation	24-Hour	1,687
		On Peak	10,035
		Off Peak	12,313
		Total	24,034
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20
2011/2012*	Obligation	24-Hour	206
		On Peak	11,857
		Off Peak	4,218
		Total	16,281
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296

* Shows seven months ended 31-Dec-2011

Figure 12-3 shows the historic FTR bid, cleared and net bid volume from June 2003 through December 2011 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume represents the volume of FTRs buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers in a given auction, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers in a given auction whether or not they cleared, excluding sell offers. The maximum bid, cleared and net bid volumes of 6,233,773 MW, 847,183 MW and 7,437,352 MW are all in June 2011. The periodic spikes represent the Long Term and Annual Auctions, which are included in the June volume at the start of each planning period in which the bids cleared. In the case of the Long Term FTR Auctions the volume is included in June of the planning period in which the first year of the FTR may take effect. For example, the 2009 to 2012 Long Term Auction is included in June 2009. The cleared volume has trended upward, consistent with transmission additions and upgrades. There is also a trend, starting in the 2007 to 2008 planning period, of the bid volume decreasing as the planning period progresses, followed by a large increase in bids in the auctions for the new planning period. The 2011 to 2012 planning period had a very large bid volume compared to prior planning periods.

35 The 2011 to 2012 planning period covers bilateral FTRs that are effective for any time between June 1, 2011 through December 31, 2011, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 12-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2011[36]



Price

The least expensive way to purchase an FTR is in the Monthly Balance of Planning Period Auctions. Within the Monthly Balance of Planning Period Auctions, it is least expensive to purchase an FTR for the shoulder months. The average price of an FTR during the Monthly Balance of Planning Period Auctions is $0.12, with May 2011 being the least expensive month at $0.06. The least expensive month and period is a bid cleared in the January 2011 auction which would cover March 2011, at $0.02.

Table 12-14 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2012 to 2015 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.05 per MW while weighted-average sell offer FTR prices were $0.24 per MW. Comparable weighted-average, buy-bid FTR prices were $0.06 per MW while weighted-average sell offer FTR prices were $0.10 per MW in the 2011 to 2014 Long Term FTR Auction.

Table 12-14 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2012 to 2015

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.66)	($0.21)	($0.29)	($0.29)
		Year 2	($1.73)	($0.19)	($0.23)	($0.24)
		Year 3	($0.50)	($0.15)	($0.20)	($0.18)
		Year All	NA	NA	NA	NA
		Total	($1.43)	($0.18)	($0.24)	($0.24)
	Prevailing Flow	Year 1	$0.99	$0.24	$0.37	$0.33
		Year 2	$1.14	$0.21	$0.33	$0.31
		Year 3	$0.94	$0.18	$0.28	$0.25
		Year All	NA	NA	NA	NA
		Total	$1.03	$0.21	$0.33	$0.30
	Total		$0.36	$0.02	$0.05	$0.05
Sell offers	Counter Flow	Year 1	($0.56)	($0.32)	($0.54)	($0.44)
		Year 2	($0.56)	($0.19)	($0.65)	($0.37)
		Year 3	NA	($0.10)	($0.11)	($0.11)
		Year All	NA	NA	NA	NA
		Total	($0.56)	($0.23)	($0.48)	($0.36)
	Prevailing Flow	Year 1	$0.92	$0.23	$0.54	$0.38
		Year 2	$1.44	$0.30	$0.64	$0.48
		Year 3	$0.29	$0.20	$0.32	$0.26
		Year All	NA	NA	NA	NA
		Total	$1.13	$0.25	$0.56	$0.41
	Total		$0.57	$0.15	$0.33	$0.24

The 2012 to 2015 Long Term FTR Auction price frequency for cleared buy bids in Figure 12-5 shows that 96.5 percent of Long Term FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). For the 2012 to 2015 Long Term FTR Auction, 99.9 percent of buy bids cleared between -$2 per MW and $2 per MW, with 19.9 percent of all buy bids clearing for $0 per MW.

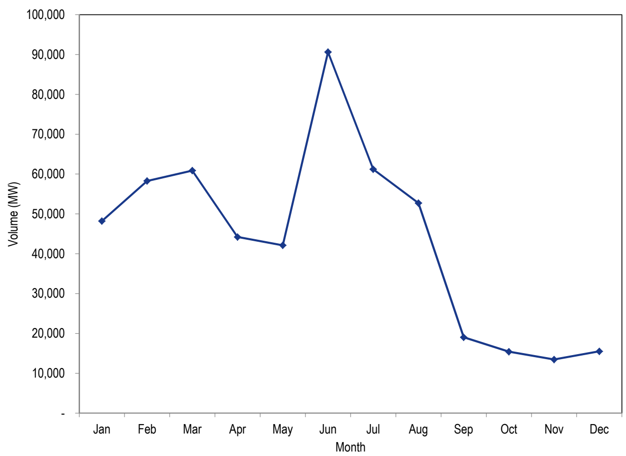
On October 31, 2011 the FERC issued an order accepting revisions to the PJM OATT with an effective date of August 5, 2011. As of that date, PJM no longer allows buy bids to clear with a price of $0 unless "there is a minimum of one binding constraint in the auction period for which the Financial Transmission Rights path sensitivity is non-zero."[37] The September 2011 Monthly Balance of Planning Period FTR Auction was the first auction affected by this rule change. The average volume of FTR MW cleared at a price of zero dropped 72.3 percent from the January 2011 through August 2011 Monthly Balance of Planning Period Auctions, to the September 2011 through December 2011 Monthly

36 The previous 3rd Quarter *State of the Market Report* did not contain volume data for Long Term FTR Auctions.

37 137 FERC ¶ 61,003 (2011).

Balance of Planning Period auctions. Figure 12-4 shows the volume of FTR buy bids that cleared with a price of $0 for the 2011 calendar year. The September 2011 Monthly Balance of Planning Period FTR Auction was the first to be affected by the zero bid rule change. Cleared bids at $0 declined substantially from August to September and subsequent auctions.

Figure 12-4 Volume of FTR buy bids cleared at $0: Calendar year 2011



The 2012 to 2015 Long Term FTR Auction price frequency for cleared buy bids in Figure 12-5 shows that 96.3 percent of Long Term FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The majority of the cleared bids for the 2012 to 2015 Long Term FTR Auction fall into the $0 to $2 range. This auction was conducted prior to the new $0 bid rule implementation.

Figure 12-5 Long Term FTR auction clearing price per MW frequency: Planning periods 2012 to 2015

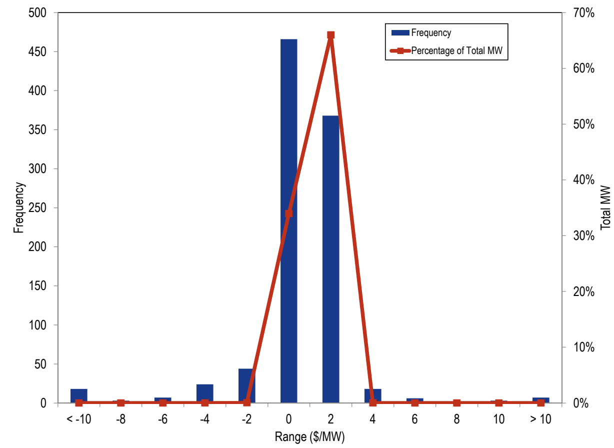


Table 12-15 shows the cleared, weighted-average prices by trade type, hedge type, FTR direction and class type for Annual FTRs during the 2011 to 2012 planning period. For the 2011 to 2012 planning period, weighted-average, buy-bid FTR obligation prices were $0.06 per MW higher than the previous planning period, while weighted-average, buy-bid FTR option prices were $0.10 per MW lower. During the 2011 to 2012 planning period, weighted-average sell offer FTR obligation and option prices were $0.12 and $0.09 per MW higher than the previous planning period.

On average during the 2011 to 2012 planning period in the Annual FTR Auction, self scheduled FTRs were priced $0.75 per MW higher than buy-bid obligation FTRs. They were priced $0.25 per MW less than the cleared, weighted-average price of self scheduled FTRs during the 2010 to 2011 planning period. Weighted-average, buy-bid FTR obligation prices were $0.12 less per MW for counter flow FTRs and $0.04 more per MW for prevailing flow FTRs compared to the previous planning period.

On average during the 2011 to 2012 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced $0.36 per MW higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $0.41 per MW higher than buy-bid prevailing flow obligation FTRs.

Table 12-15 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2011 to 2012

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.76)	($0.51)	($0.38)	($0.47)
		Prevailing Flow	$1.04	$0.86	$0.62	$0.79
		Total	$0.68	$0.44	$0.28	$0.41
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.89	$0.20	$0.11	$0.16
		Total	$0.89	$0.20	$0.11	$0.16
Self-scheduled bids	Obligations	Counter Flow	($0.11)	NA	NA	($0.11)
		Prevailing Flow	$1.20	NA	NA	$1.20
		Total	$1.16	NA	NA	$1.16
Buy and self-scheduled bids	Obligations	Counter Flow	($0.62)	($0.51)	($0.38)	($0.46)
		Prevailing Flow	$1.15	$0.86	$0.62	$0.91
		Total	$1.00	$0.44	$0.28	$0.58
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.89	$0.20	$0.11	$0.16
		Total	$0.89	$0.20	$0.11	$0.16
Sell offers	Obligations	Counter Flow	($3.16)	($0.70)	($0.61)	($0.87)
		Prevailing Flow	$1.09	$0.71	$0.41	$0.59
		Total	($0.12)	$0.51	$0.21	$0.34
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$2.05	$0.47	$0.75
		Total	$0.00	$2.05	$0.47	$0.75

The 2011 to 2012 planning period price frequency for cleared buy bids in Figure 12-6 shows that 87.1 percent of Annual FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The 2011 to 2012 planning period FTR obligation price frequency for cleared buy bids in Figure 12-6 shows that 85.2 percent of annual FTR obligations were purchased for less than $1 per MW. The 2011 to 2012 planning period FTR option frequency for cleared buy bids in Figure 12-6 shows that 98.0 percent of annual FTR options were purchased for less than $1 per MW. Buy bids, obligation buy bids and option buy bids cleared for $0 per MW accounted for 16.4, 14.4 and 28.3 percent of the annual volume.

Figure 12-6 Annual FTR auction clearing price per MW: Planning period 2011 to 2012

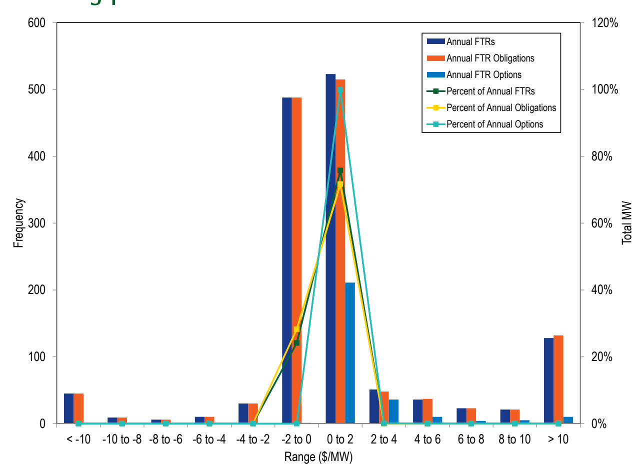


Table 12-16 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2011 through December 2011. For example, for the June 2011 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2011 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2011 to 2012 planning period was $0.10 per MW, compared with $0.13 per MW for the full 12-month 2010 to 2011 planning period.

Table 12-16 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): Calendar year 2011

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	$0.13	$0.36	$0.02				$0.28	$0.17
Feb-11	$0.08	$0.13	$0.11				$0.18	$0.10
Mar-11	$0.09	$0.16	$0.15				$0.04	$0.09
Apr-11	$0.07	$0.23						$0.08
May-11	$0.06							$0.06
Jun-11	$0.06	$0.15	$0.07	$0.33	$0.12	$0.20	$0.13	$0.13
Jul-11	$0.10	$0.15	$0.03		$0.01	$0.14	$0.02	$0.08
Aug-11	$0.12	$0.04	$0.10		$0.17	$0.20	$0.13	$0.14
Sep-11	$0.11	$0.24	$0.18		$0.20	$0.24	$0.15	$0.16
Oct-11	$0.09	$0.17	$0.09			$0.20	$0.11	$0.12
Nov-11	$0.09	$0.25	$0.13			$0.11	$0.11	$0.11
Dec-11	$0.10	$0.33	$0.18			$1.41	$0.25	$0.19

Revenue

Long Term FTR Auction Revenue

Table 12-17 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2012 to 2015 Long Term FTR Auction netted $20.5 million in revenue, $29.3 million less than the previous Long Term FTR Auction. Buyers paid $54.4 million and sellers received $33.8 million, down $10.8 million and up $17.4 million over the previous Long Term FTR Auction.

For the 2012 to 2015 Long Term FTR Auction, the counter flow FTRs netted -$117.5 million in revenue, down $72.2 million from the previous Long Term FTR Auction, with buyers receiving $128.3 million and sellers paying $10.8 million. Prevailing flow FTRs netted $138.0 million in revenue, down $101.5 million from the previous Long Term FTR Auction, with buyers paying $182.7 million and sellers receiving $44.6 million.

Table 12-18 shows that overall, net revenue from the 2012 to 2015 Long Term FTR Auction is down from $49.8 million to $20.5 million (58.8 percent) from the 2011 to 2014 Long Term FTR Auction and is the lowest net revenue in the history of the Long Term FTR Auction. This may be attributed to several factors, including an increase in counter flow buy bids, which participants are paid to take, decreasing initial revenue by $128.3 million for the 2012 to 2015 auction. Another factor is the increase in Long Term FTR sell offers, which have been steadily increasing since the Long Term FTR Auction's inception, with the 2012 to 2015 Long Term FTR Auction more than twice the sell offer revenue in the prior Long Term Auction. There was no cleared volume for three year long term FTRs in the 2012 to 2015 Long Term FTR Auction, and three year FTR demand has steadily decreased since the inception of the Long Term FTR Auction.

Figure 12-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2012 to 2015 Long Term FTR Auction.[38] The top 10 positive revenue producing FTR sinks accounted for $53.6 million of the total revenue of $20.5 million paid in the auction.[39] They also comprised 3.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$26.8 million of revenue and constituted 3.9 percent of all FTRs bought in the auction.

38 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

39 The total positive revenue producing FTR sinks was $120.56 million and the total negative revenue producing FTR sinks was -$100.64 million. The overall revenue paid in the auction was $20.5 million.

Table 12-17 Long Term FTR Auction revenue: Planning periods 2012 to 2015

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($8,646,093)	($26,837,405)	($22,445,688)	($57,929,185)
		Year 2	($4,681,619)	($18,461,021)	($16,140,474)	($39,283,114)
		Year 3	($1,047,559)	($16,584,285)	($13,471,719)	($31,103,562)
		Year All	$0	$0	$0	$0
		Total	($14,375,271)	($61,882,711)	($52,057,880)	($128,315,861)
	Prevailing Flow	Year 1	$11,599,289	$39,631,430	$28,817,525	$80,048,244
		Year 2	$10,702,005	$26,490,902	$19,897,739	$57,090,646
		Year 3	$5,397,207	$23,259,187	$16,882,121	$45,538,515
		Year All	$0	$0	$0	$0
		Total	$27,698,501	$89,381,519	$65,597,385	$182,677,404
	Total		$13,323,230	$27,498,808	$13,539,504	$54,361,543
Sell offers	Counter Flow	Year 1	($448,019)	($3,540,398)	($2,079,186)	($6,067,603)
		Year 2	($316,731)	($2,587,881)	($1,325,663)	($4,230,275)
		Year 3	0	($304,508)	($222,651)	($527,158)
		Year All	NA	NA	NA	NA
		Total	($764,749)	($6,432,787)	($3,627,500)	($10,825,036)
	Prevailing Flow	Year 1	$1,383,987	$14,787,335	$7,770,664	$23,941,986
		Year 2	$1,743,472	$10,853,714	$6,159,723	$18,756,909
		Year 3	19,843	$1,126,699	$799,056	$1,945,599
		Year All	NA	NA	NA	NA
		Total	$3,147,302	$26,767,748	$14,729,444	$44,644,494
	Total		$2,382,553	$20,334,961	$11,101,944	$33,819,458
Total			$10,940,678	$7,163,847	$2,437,560	$20,542,085

Table 12-18 Long Term FTR Auction revenue from the 2009 to 2012 Auction through the 2012 to 2015 Auction

Trade Type	FTR Direction	Period Type	2009/2012 Auction	2010/2013 Auction	2011/2014 Auction	2012/2015 Auction
Buy	Counterflow	Year 1	($47,506,196)	($43,961,311)	($87,222,994)	($57,929,185)
		Year 2	($29,119,334)	($25,626,515)	($57,552,497)	($39,283,113)
		Year 3	($16,628,100)	($17,992,866)	($47,339,689)	($31,103,562)
		Year All	($1,606,901)	($308,164)	($698,514)	$0
		Total	($94,860,532)	($87,888,858)	($192,813,696)	($128,315,861)
	Prevailing Flow	Year 1	$61,492,662	$58,440,660	$116,381,205	$80,048,243
		Year 2	$35,079,120	$38,579,690	$76,449,064	$57,090,645
		Year 3	$17,460,435	$28,763,253	$66,139,797	$45,538,514
		Year All	$21,043,160	$1,211,686	$44,581	$0
		Total	$135,075,378	$126,995,291	$259,014,648	$182,677,404
	Total		$40,214,845	$39,106,433	$66,200,951	$54,361,542
Sell	Counterflow	Year 1	($151,195)	($161,452)	($2,564,824)	($6,067,602)
		Year 2	($159,891)	($37,500)	($467,168)	($4,230,274)
		Year 3	($589,019)	($10,019)	($110,827)	($527,158)
		Total	($900,106)	($208,972)	($3,142,820)	($10,825,036)
	Prevailing Flow	Year 1	$1,158,167	$3,697,625	$12,076,791	$23,941,985
		Year 2	$323,559	$4,041,231	$6,642,893	$18,756,909
		Year 3	$701,827	$441,407	$821,794	$1,945,598
		Total	$2,183,554	$8,180,264	$19,541,479	$44,644,493
	Total		$1,283,448	$7,971,291	$16,398,658	$33,819,457
Net Revenue			$38,931,397	$31,135,141	$49,802,292	$20,542,085

Figure 12-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2012 to 2015[40]

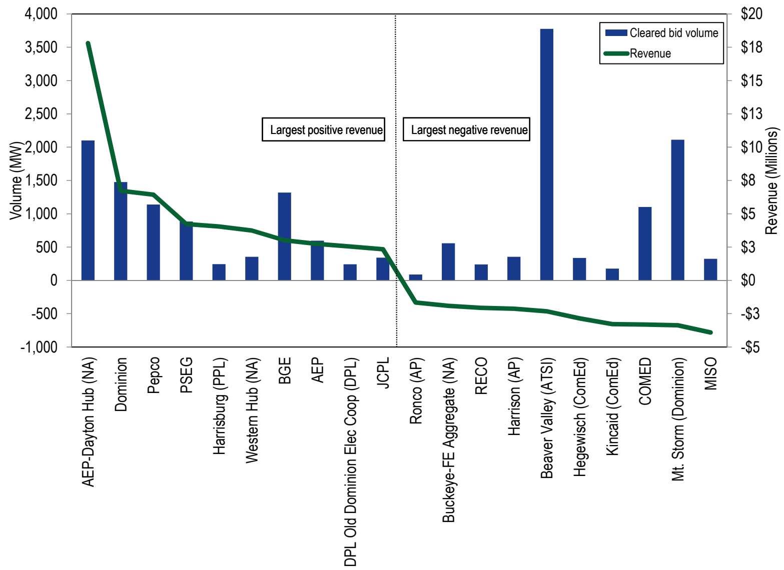
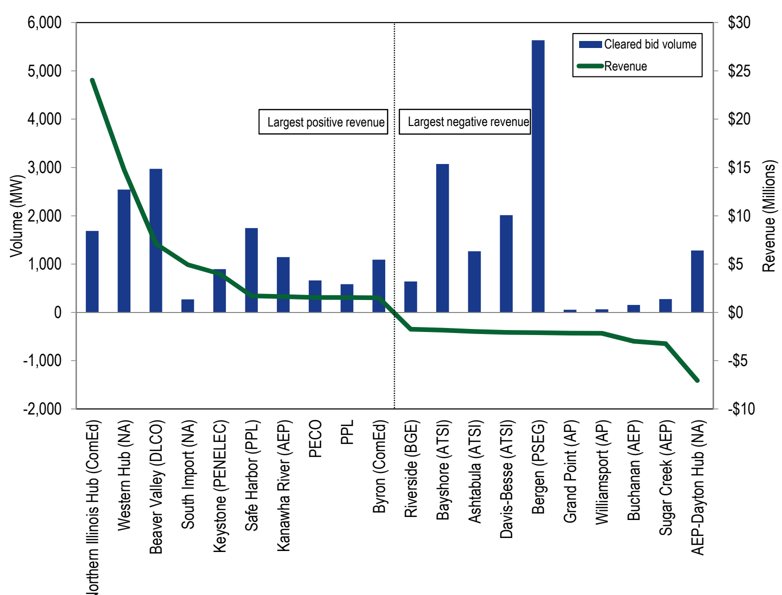


Figure 12-8 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2012 to 2015



40 For Figure 12-7 through Figure 12-15, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 12-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2012 to 2015 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $62.78 million of the total revenue of $19.28 million paid in the auction. They also comprised 5.9 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$27.34 million of revenue and constituted 6.3 percent of all FTRs bought in the auction.

Annual FTR Auction Revenue

Table 12-19 shows Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. For the 2011 to 2012 planning period, the Annual FTR Auction revenue was down $20.2 million to $1,029.6 million from the previous Annual FTR Auction, with buyers paying $1,068.3 million, up $8.3 million, and sellers receiving $38.6 million, up $28.4 million from the previous Annual FTR Auction.

For the 2011 to 2012 planning period, counter flow FTRs in the Annual FTR Auction netted -$182.3 million in revenue, increased -$61.3 million over the previous Annual FTR Auction, with buyers receiving $198.8 million and sellers paying $16.5 million, and the prevailing flow FTRs in the Annual FTR Auction netted $1,212.0 million in revenue, up $41.2 million from the previous Annual FTR Auction, with buyers paying $1,267.1 million and sellers receiving $55.1 million. Since counter flow FTRs bids are paid to take the FTRs, the FTR revenues for counter flow FTR bids are negative and FTR revenues for sales of counter flow FTRs are positive.

Figure 12-9 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2011 to 2012 planning period. The top 10 positive revenue producing FTR

Table 12-19 Annual FTR Auction revenue: Planning period 2011 to 2012

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($31,727,221)	($86,595,481)	($79,270,931)	($197,593,633)
		Prevailing Flow	$173,929,276	$333,218,996	$253,894,947	$761,043,219
		Total	$142,202,056	$246,623,514	$174,624,016	$563,449,586
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,243,985	$19,888,318	$12,943,329	$34,075,631
		Total	$1,243,985	$19,888,318	$12,943,329	$34,075,631
	Total	Counter Flow	($31,727,221)	($86,595,481)	($79,270,931)	($197,593,633)
		Prevailing Flow	$175,173,262	$353,107,313	$266,838,275	$795,118,850
		Total	$143,446,041	$266,511,832	$187,567,345	$597,525,217
Self-scheduled bids	Obligations	Counter Flow	($1,219,303)	NA	NA	($1,219,303)
		Prevailing Flow	$471,940,076	NA	NA	$471,940,076
		Total	$470,720,773	NA	NA	$470,720,773
Buy and self-scheduled bids	Obligations	Counter Flow	($32,946,524)	($86,595,481)	($79,270,931)	($198,812,936)
		Prevailing Flow	$645,869,353	$333,218,996	$253,894,947	$1,232,983,295
		Total	$612,922,829	$246,623,514	$174,624,016	$1,034,170,359
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$1,243,985	$19,888,318	$12,943,329	$34,075,631
		Total	$1,243,985	$19,888,318	$12,943,329	$34,075,631
	Total	Counter Flow	($32,946,524)	($86,595,481)	($79,270,931)	($198,812,936)
		Prevailing Flow	$647,113,338	$353,107,313	$266,838,275	$1,267,058,926
		Total	$614,166,814	$266,511,832	$187,567,345	$1,068,245,990
Sell offers	Obligations	Counter Flow	($5,147,167)	($5,228,336)	($6,092,443)	($16,467,946)
		Prevailing Flow	$4,479,226	$33,317,024	$16,705,071	$54,501,321
		Total	($667,941)	$28,088,688	$10,612,627	$38,033,375
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$275,150	$294,744	$569,895
		Total	$0	$275,150	$294,744	$569,895
	Total	Counter Flow	($5,147,167)	($5,228,336)	($6,092,443)	($16,467,946)
		Prevailing Flow	$4,479,226	$33,592,175	$16,999,815	$55,071,216
		Total	($667,941)	$28,363,839	$10,907,372	$38,603,270
Total			$614,834,755	$238,147,993	$176,659,973	$1,029,642,720

sinks accounted for $871.5 million (84.6 percent) of the total revenue of $1,029.7 million paid in the auction. They also comprised 27.3 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$71.2 million of revenue and constituted 3.0 percent of all FTRs bought in the auction.

Figure 12-9 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2011 to 2012

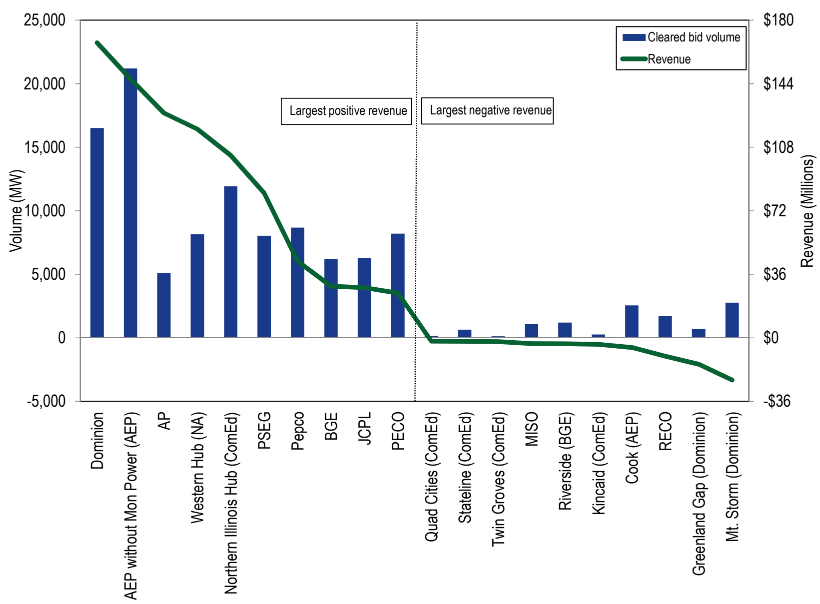
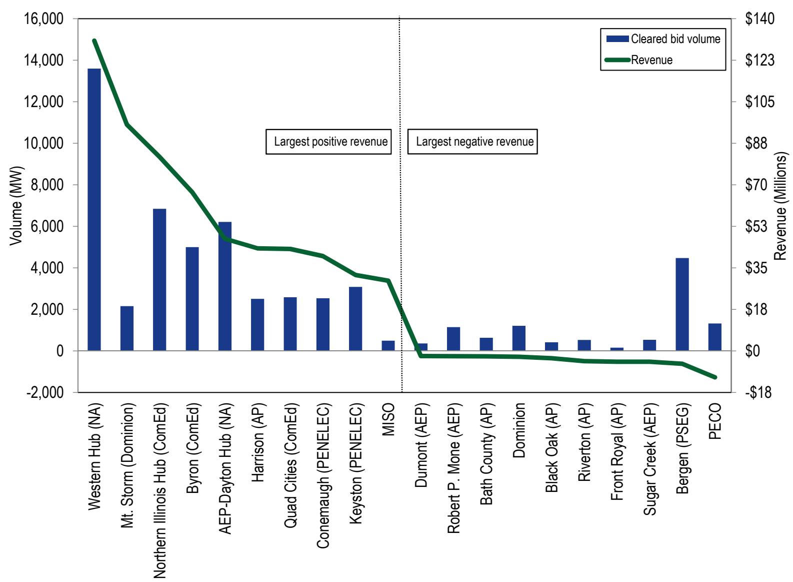


Figure 12-10 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2011 to 2012 planning period. The top 10 positive revenue producing FTR sources accounted for $609.82 million (59.2 percent) of the total revenue of $1,030.96 million paid in the auction. They also comprised 12.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$42.30 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

Figure 12-10 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2011 to 2012



Monthly Balance of Planning Period FTR Auction Revenue

Table 12-20 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type. For the 2011 to 2012 planning period through December 31, 2011, the Monthly Balance of Planning Period FTR Auctions netted $22.1 million in revenue, with buyers paying $106.4 million and sellers receiving $84.3 million. For the entire 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions netted $41.8 million in revenue, with buyers paying $35.5 million and sellers receiving $77.3 million.

Figure 12-11 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2011 to 2012 planning period. The top 10 positive revenue producing FTR sinks accounted for $45.6 million of revenue and 3.6 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. The top 10 negative revenue producing FTR sinks accounted for -$16.5 million of revenue and constituted 1.8 percent of all FTRs bought in the auctions. The MW volume is the net of all buys and sells from the Monthly Balance of Planning Period FTR Auctions during the 2011 to 2012 planning period. The net market volume sinking in the Dominion zone was negative since the total cleared volume of the monthly FTR buy bids sinking in the Dominion zone was less than the total cleared volume of the monthly FTR sell offers sinking in the Dominion zone.

Figure 12-12 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2011 to 2012 planning period. The top 10 positive revenue producing FTR sources accounted for $54.72 million and 4.1 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$16.76 million of revenue and constituted 0.6 percent of all FTRs bought in the auctions.

Table 12-20 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2011

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-11	Obligations	Buy bids	($1,205,888)	$7,104,026	$6,539,294	$12,437,433
		Sell offers	$1,138,221	$2,625,465	$4,050,289	$7,813,975
	Options	Buy bids	$0	$136,353	$87,800	$224,153
		Sell offers	$0	$1,812,131	$686,209	$2,498,340
Feb-11	Obligations	Buy bids	($36,220)	$4,296,859	$3,345,841	$7,606,480
		Sell offers	$587,026	$1,938,472	$2,305,072	$4,830,570
	Options	Buy bids	$0	$126,188	$25,671	$151,859
		Sell offers	$1,947	$1,218,343	$389,391	$1,609,682
Mar-11	Obligations	Buy bids	($101,074)	$4,605,081	$3,368,274	$7,872,281
		Sell offers	$423,197	$2,274,909	$1,933,265	$4,631,371
	Options	Buy bids	$14,085	$292,986	$178,090	$485,161
		Sell offers	$5,149	$1,231,751	$454,338	$1,691,239
Apr-11	Obligations	Buy bids	$374,217	$2,884,005	$1,629,459	$4,887,681
		Sell offers	$677,941	$1,461,719	$878,890	$3,018,551
	Options	Buy bids	$4,569	$88,824	$54,691	$148,084
		Sell offers	$3,727	$721,783	$403,883	$1,129,392
May-11	Obligations	Buy bids	$451,258	$2,063,976	$1,214,403	$3,729,637
		Sell offers	$210,714	$1,074,632	$567,818	$1,853,164
	Options	Buy bids	$0	$91,362	$181,717	$273,078
		Sell offers	$185	$539,763	$393,717	$933,665
Jun-11	Obligations	Buy bids	$1,960,494	$13,115,229	$8,318,764	$23,394,487
		Sell offers	$5,175,453	$5,288,319	$2,797,969	$13,261,740
	Options	Buy bids	$0	$186,515	$192,243	$378,758
		Sell offers	$0	$3,103,330	$2,147,165	$5,250,495
Jul-11	Obligations	Buy bids	$2,169,505	$6,367,118	$4,209,356	$12,745,978
		Sell offers	($2,192,924)	$4,283,630	$2,794,481	$4,885,187
	Options	Buy bids	$51,761	$1,117,027	$549,087	$1,717,875
		Sell offers	$0	$2,862,215	$1,919,105	$4,781,320
Aug-11	Obligations	Buy bids	$452,651	$12,262,357	$5,644,491	$18,359,499
		Sell offers	$331,875	$7,816,757	$3,706,720	$11,855,353
	Options	Buy bids	$0	$596,709	$482,609	$1,079,318
		Sell offers	$0	$2,652,228	$1,190,174	$3,842,402
Sep-11	Obligations	Buy bids	$1,787,959	$8,393,963	$3,116,850	$13,298,772
		Sell offers	$276,769	$5,516,851	$2,229,736	$8,023,356
	Options	Buy bids	$9,087	$722,750	$580,167	$1,312,004
		Sell offers	$0	$2,173,747	$1,218,088	$3,391,835
Oct-11	Obligations	Buy bids	$510,469	$6,508,454	$4,002,264	$11,021,187
		Sell offers	$301,550	$3,303,791	$2,146,912	$5,752,253
	Options	Buy bids	$0	$348,970	$340,721	$689,691
		Sell offers	$0	$1,714,474	$1,154,194	$2,868,668
Nov-11	Obligations	Buy bids	$1,811,171	$4,565,795	$2,214,612	$8,591,579
		Sell offers	$317,883	$3,965,511	$1,649,356	$5,932,751
	Options	Buy bids	$0	$426,283	$262,337	$688,620
		Sell offers	$3,388	$1,390,406	$851,088	$2,244,883
Dec-11	Obligations	Buy bids	$787,210	$5,304,596	$6,602,766	$12,694,571
		Sell offers	($435,710)	$4,610,174	$5,744,990	$9,919,454
	Options	Buy bids	$0	$230,986	$198,041	$429,027
		Sell offers	$2,829	$1,271,168	$1,006,526	$2,280,523
2010/2011*	Obligations	Buy bids	($439,619)	$27,205,953	$19,325,016	$46,091,350
		Sell offers	$3,037,099	$9,572,999	$9,892,420	$22,502,518
	Options	Buy bids	$49,085	$2,361,970	$2,364,609	$4,775,664
		Sell offers	$601,925	$12,511,499	$7,966,991	$21,080,415
	Total		($4,029,558)	$7,483,426	$3,830,213	$7,284,081
2011/2012**	Obligations	Buy bids	$9,479,458	$56,517,511	$34,109,103	$100,106,073
		Sell offers	$3,774,896	$34,785,034	$21,070,164	$59,630,094
	Options	Buy bids	$60,848	$3,629,240	$2,605,205	$6,295,292
		Sell offers	$6,217	$15,167,568	$9,486,341	$24,660,126
	Total		$5,759,194	$10,194,149	$6,157,804	$22,111,146

* Shows Twelve Months for 2010/2011; ** Shows seven months ended 31-Dec-2011 for 2011/2012

Figure 12-11 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through December 31, 2011

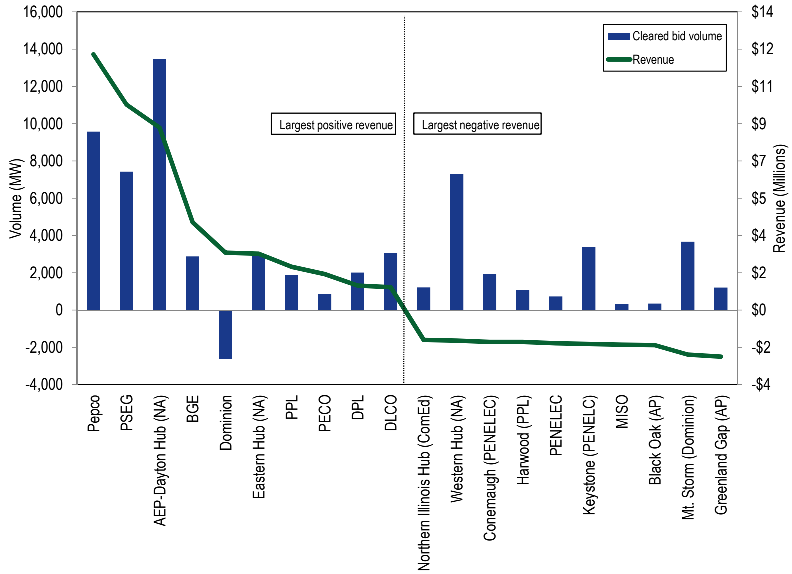
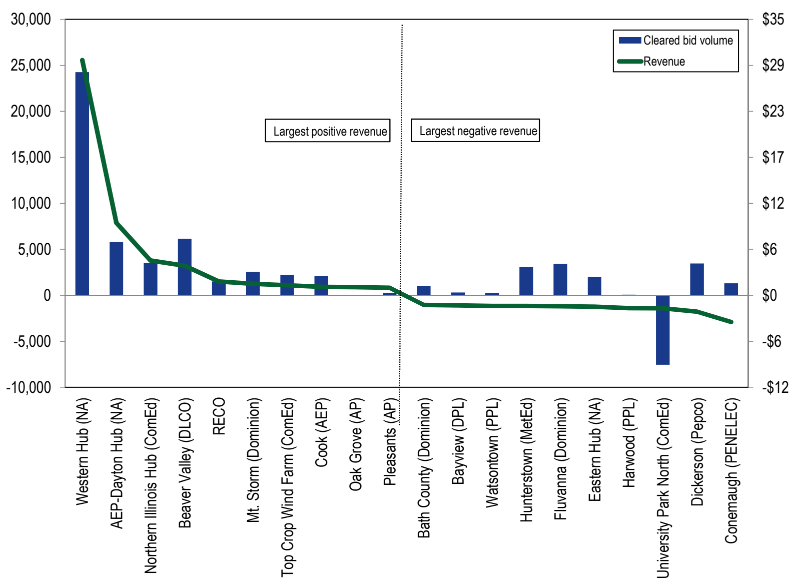


Figure 12-12 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through December 31, 2011



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[41] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion to the target allocations across specific paths for which FTRs were available and purchased. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

41 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

FTRs are paid each month from congestion revenues, both day ahead and balancing, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2010 to 2011 planning period, FTRs were not fully funded and thus an uplift charge was collected.

Table 12-21 shows the composition of FTR target allocations and FTR revenues for the 2010 to 2011 and the 2011 to 2012 planning periods, with the latter shown through December 31, 2011. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue, from the day ahead and balancing markets, and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 12-21 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO whose operating limits are respected by PJM.[42] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.1 million in congestion charges to Con Edison in the 2011 to 2012 planning period through December 31, 2011.[43,44]

For the current planning period, no charges have been made to the Day Ahead Operating Reserves. These charges may be necessary if the hourly congestion revenues are negative at the end of the month. If this happens, charges are made and allocated as additional Day-Ahead Operating Reserves charges during the month. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation. This is accounted for as a charge, which is allocated to Day-Ahead Operating Reserves. This type of adjustment is infrequent, occurring only three times in the 2010 to 2011 planning period.

Table 12-21 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012

Accounting Element	2010/2011	2011/2012*
ARR information		
ARR target allocations	$1,031.0	$574.7
FTR auction revenue	$1,097.8	$639.1
ARR excess	$66.9	$64.4
FTR targets		
FTR target allocations	$1,687.6	$672.7
Adjustments:		
Adjustments to FTR target allocations	($1.8)	($0.8)
Total FTR targets	$1,685.8	$671.9
FTR revenues		
ARR excess	$66.9	$64.4
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($59.5)	($33.2)
Hourly congestion revenue	$1,464.9	$597.0
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($47.8)	($58.2)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.8)	($0.1)
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$2.6	$0.0
Other adjustments to FTR revenues	2.34	$0.5
Total FTR revenues	$1,430.7	$570.3
Excess revenues distributed to other months	($4.6)	$0.0
Net Negative Congestion charged to DA Operating Reserves	$7.3	$0.0
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$1,433.4	$570.3
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,434.2	$570.5
Remaining deficiency	$252.4	$101.6

* Shows seven months ended 31-Dec-11

42 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

43 111 FERC ¶ 61,228 (2005).

44 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts" and Appendix E, "Interchange Transactions" at Table D-2, "Con Edison and PSE&G wheel settlements data: Calendar year 2010."

Table 12-22 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-10	$194.2	$196.1	97.8%	$194.2	99.0%	($1.9)
Jul-10	$275.0	$273.0	100.0%	$273.0	100.0%	$0.0
Aug-10	$111.3	$119.2	93.2%	$111.3	93.4%	($7.9)
Sep-10	$116.7	$165.3	70.0%	$116.7	70.6%	($48.5)
Oct-10	$52.4	$67.4	77.4%	$52.4	77.8%	($14.9)
Nov-10	$50.0	$80.0	61.9%	$50.0	62.6%	($29.9)
Dec-10	$185.0	$185.0	73.2%	$185.0	100.0%	$0.0
Jan-11	$245.4	$249.5	98.3%	$245.4	98.4%	($4.0)
Feb-11	$79.4	$93.0	85.0%	$79.4	85.4%	($13.6)
Mar-11	$48.2	$45.6	100.0%	$45.6	100.0%	$0.0
Apr-11	$38.4	$73.2	52.4%	$38.4	52.4%	($34.8)
May-11	$34.6	$72.5	45.1%	$34.6	47.7%	($37.9)
Summary for Planning Period 2010 to 2011						
Total	$1,426.1	$1,619.6		$1,426.1	88.1%	($193.5)
Jun-11	$134.6	$154.6	86.9%	$134.6	87.1%	($20.0)
Jul-11	$178.2	$181.4	97.8%	$178.2	98.3%	($3.1)
Aug-11	$70.7	$73.4	96.2%	$70.7	96.3%	($2.7)
Sep-11	$69.4	$88.3	78.6%	$69.4	78.7%	($18.8)
Oct-11	$38.2	$52.3	73.0%	$38.2	73.0%	($14.1)
Nov-11	$32.8	$57.2	57.4%	$32.8	57.4%	($24.4)
Dec-11	$46.4	$64.8	71.6%	$46.4	71.6%	($18.4)
Summary for Planning Period 2011 to 2012 through December 31, 2011						
Total	$570.3	$671.9		$570.3	84.9%	($101.6)

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to compensate FTR holders fully for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 12-22 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 12-22 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months. For the 2010 to 2011 planning period, the total FTR revenues and FTR credits were $1,426.1 million which was $193.5 million less than the total FTR Target Allocations. For the first seven months of the 2010 to 2011 planning period, there is a deficiency of $101.6 million compared to the $671.9 million in FTR target allocations.

Figure 12-13 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through December 2011. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-13 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2011 to 2012 planning period may change if excess revenue is collected in the remainder of the planning period. May 2011 has the lowest monthly payout ratio since January 2004, of 51.8 percent.

Figure 12-13 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to December 2011

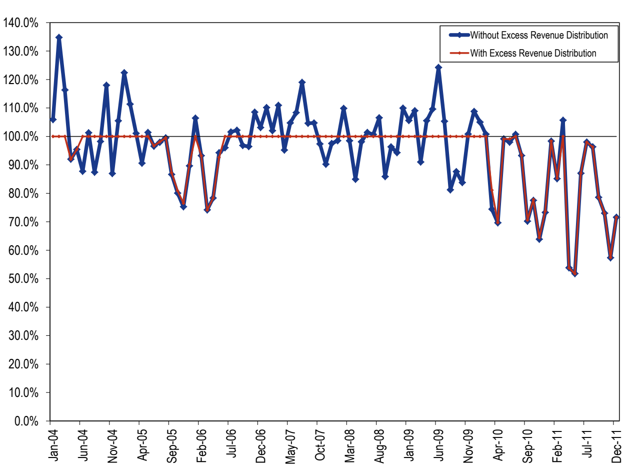


Table 12-23 shows the FTR payout ratio by planning period. FTRs were paid at 85.0 percent of the target allocation level for the 2010 to 2011 planning period and were paid at 84.9 percent of the target allocation level for the 2011 to 2011 planning period through December 31, 2011.

Table 12-23 FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012*	84.9%

* through December 31, 2011

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2011 to 2012 planning period through December 31, 2011. Figure 12-14 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 27.7 percent of total positive target allocations during the first seven months of the 2011 to 2012 planning period. FTRs with AEP without Mon Power as the sink included 5.3 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 15.2 percent of total negative target allocations. FTRs with AEP without Mon Power as the sink encompassed 2.9 percent of all negative target allocations.

Figure 12-14 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2011 to 2012 through December 31, 2011

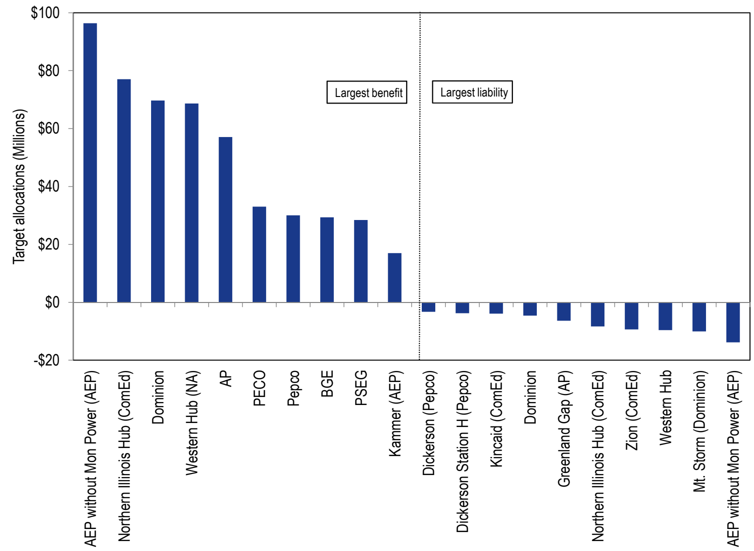
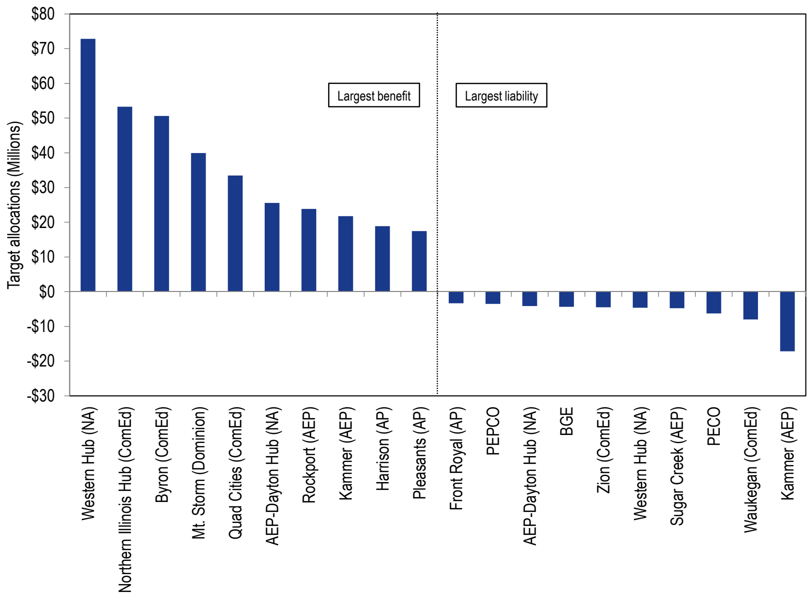


Figure 12-15 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2011 to 2012 planning period. The top 10 sources with a positive target allocation accounted for 19.6 percent of total positive target allocations. FTRs with the Western Hub as their source included 4.0 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 12.6 percent of total negative target allocations. FTRs with Kammer as the source encompassed 3.6 percent of all negative target allocations.

Table 12-24 FTR profits by organization type and FTR direction: Calendar year 2011

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($264,471,222)	$562,471,311	$44,219,620	($1,959,447)	$340,260,261
Financial	($23,247,851)	NA	$148,945,344	NA	$125,697,493
Total	($287,719,074)	$562,471,311	$193,164,964	($1,959,447)	$465,957,753

Figure 12-15 Ten largest positive and negative FTR target allocations summed by source: Planning period 2011 to 2012 through December 31, 2011



Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the revenue that an FTR holder receives, after adjusting by the FTR payout ratio for the planning period, and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder receives and the FTR credits are the cost to the FTR holder. The cost of self scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 12-24 lists FTR profits by organization type and FTR direction for the 2011 calendar year. FTR profits are the sum of the daily FTR credits, including self scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR payout ratio was 85.0 percent of the target allocation for the 2010 to 2011 planning period and 84.9 percent for the first seven months of the 2011 to 2012 planning period. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self scheduled FTRs have zero cost. The results indicate the total FTR profits in 2011 were $125.7 million for financial entities and $340.3 million for physical entities. As shown in Table 12-24, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self scheduled, were not profitable in 2011. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2011.

Table 12-25 lists the monthly FTR profits in the 2011 calendar year by organization type. Self scheduled FTRs are listed separately from physical profits to illustrate their impact on overall profits. Total FTR profits were positive and larger in magnitude during the winter and summer months when congestion tended to be higher. The three most profitable months for FTRs were January, July and June. FTR profits decreased during the shoulder months when congestion is less.

Table 12-25 Monthly FTR profits by organization type: Calendar year 2011

	Organization Type			
Month	Physical	Financial	Self Scheduled FTRs	Total
Jan	79,189,162	$34,569,527	$58,567,763	$172,326,451
Feb	(13,218,579)	$6,234,007	$52,899,915	$45,915,343
Mar	(70,148,251)	$11,727,961	$58,567,763	$147,474
Apr	(43,162,414)	$13,172,564	$56,678,480	$26,688,630
May	(42,156,510)	$8,445,825	$58,567,763	$24,857,079
Jun	16,514,654	$23,815,782	$38,583,670	$78,914,106
Jul	24,445,242	$35,064,490	$39,869,792	$99,379,524
Aug	(27,433,989)	($4,665,815)	$39,869,792	$7,769,988
Sep	(18,312,069)	$1,807,355	$38,583,670	$22,078,956
Oct	(47,018,209)	($2,241,775)	$39,869,792	($9,390,192)
Nov	(39,093,476)	($2,574,032)	$38,583,670	($3,083,838)
Dec	(39,857,164)	$341,603	$39,869,792	$354,231
Total	(220,251,603)	$125,697,493	$560,511,863	$465,957,753

Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[45] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available only as obligations (not options) and 24-hour products. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated as load shifts between LSEs within the transmission zone.

On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the 2011 to 2012 Annual ARR Allocation. For a transitional period, those customers that receive, and pay for, firm transmission service that sources or sinks in newly integrated PJM control zones may elect to receive a direct allocation of FTRs instead of an allocation of ARRs. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into PJM.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2010 to 2011 planning period, all eligible market participants were allocated ARRs. For the 2011 to 2012 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the ATSI control zone.

45 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top three binding transmission constraints for the 2011 to 2012 planning period can be seen in Figure 12-1.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[46] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self schedule their Long Term ARRs as FTRs. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[47]
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.
- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[48] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[49]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system

46 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

47 See PJM. "Manual 6: Financial Transmission Rights" Revision 12 (July 1, 2009), p. 22.

48 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.

49 See "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[50] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 12-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[51]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduced allocation of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

Table 12-26 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity that limited supply in the annual ARR allocation for the 2011 to 2012 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[52] The violation degree is a measure of the MW that a constraint is over the limit.

Table 12-26 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2011 to 2012

Constraint	Type	Control Zone
South Mahwah - Waldwick	Line	PSEG
East Frankfort - Crete	Line	ComEd
Crete - St Johns Tap	Flowgate	MISO
Linden - North Ave	Line	PSEG
Bayonne - PVSC	Line	PSEG
Electric Junction - Nelson	Line	MISO
Bayonne - Marion	Line	PSEG
Pleasant Valley - Belvidere	Line	ComEd
East Sayre - North Waverly	Line	PENELEC
Breed - Wheatland	Line	AEP

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs based on the resultant increase in transmission capability.[53] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two.

50 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.
51 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.
52 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.
53 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.

Incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

Table 12-27 lists the incremental ARR allocation volume for the 2008 to 2009, 2009 to 2010, 2010 to 2011 and the 2011 to 2012 planning periods. For the 2011 to 2012 planning period, there were requests for 595 MW and 100 percent of the bids were cleared. For the 2010 to 2011 planning period, there were bids for 531 MW and 100 percent of the bids were cleared.

Incremental ARRs (IARRs) for RTEP Upgrades

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[55] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone. For the annual ARR allocation for the 2011/2012 planning period, 678.2 total MW of IARRs were allocated for RTEP upgrades. Table 12-28 lists the three RTEP upgrade projects that were allocated IARRs.

Table 12-27 Incremental ARR allocation volume: Planning periods 2008 to 2009, 2009 to 2010, 2010 to 2011 and 2011 to 2012

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%
2011/2012	15	595	595	100%	0	0%

Table 12-28 IARRs allocated for 2011 to 2012 Annual ARR Allocation for RTEP upgrades[54]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

54 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following ten pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03.

55 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[56] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARR for the receiving LSE compared to the total value held by the original ARR holder.

The MMU recommends that when load switches between LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. At the time of the FTR Annual Auction, ARR holders have the ability to acquire FTRs by choosing to self schedule in the annual FTR auction. When load switches among LSEs during the planning period, the LSE gaining load is reassigned its proportional share of the ARRs from the LSE losing load. After the Annual FTR Auction has occurred, the LSE gaining load does not have the ability to self schedule FTRs associated with the reassigned ARRs. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

56 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Table 12-29 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2010 and December 2011. About 24,531 MW of ARRs associated with $388,700 per MW-day of revenue were automatically reassigned in the first seven months of the 2010 to 2011 planning period. About 56,296 MW of ARRs with $1,043,700 per MW-day of revenue were reassigned for the entire 12-month 2010 to 2011 planning period.

Table 12-29 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2010, through December 31, 2011

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2010/2011 (12 months)	2011/2012 (7 months)*	2010/2011 (12 months)	2011/2012 (7 months)*
AECO	887	345	$6.0	$3.7
AEP	961	3,333	$21.4	$65.6
AP	4,992	961	$481.1	$87.1
ATSI	0	2,474	$0.0	$10.7
BGE	3,359	2,117	$50.5	$37.3
ComEd	3,064	2,271	$60.2	$40.3
DAY	193	318	$0.6	$0.5
DLCO	5,502	2,172	$25.7	$7.9
DPL	2,252	1,364	$20.4	$12.2
Dominion	0	1	$0.0	$0.0
JCPL	3,490	802	$28.8	$7.3
Met-Ed	3,947	877	$51.9	$15.3
PECO	12,284	1,291	$89.2	$15.5
PENELEC	3,745	803	$53.5	$16.3
PPL	5,734	2,518	$74.4	$28.7
PSEG	3,416	1,235	$52.8	$20.4
Pepco	2,470	1,649	$27.3	$20.0
RECO	143	46	$0.1	$0.0
Total	56,296	24,531	$1,043.7	$388.7

* Through 31-Dec-11

Market Performance

Volume

Table 12-30 lists the annual ARR allocation volume by stage and round for the 2010 to 2011 and the 2011 to 2012 planning periods. For the 2011 to 2012 planning period, there were 64,160 MW (43.2 percent of total demand) bid in Stage 1A, 22,208 MW (18.4 percent of total demand) bid in Stage 1B and 57,053 MW (38.4 percent of total demand) bid in Stage 2. Of 148,538 MW in total ARR requests 64,160 MW were allocated in Stage 1A and 22,208 MW were allocated in Stage 1B while 16,108 MW were allocated in Stage 2 for a total of 102,476 MW (69.0 percent) allocated. Eligible market participants subsequently converted 46,017 MW of these allocated ARRs into Annual FTRs (44.9 percent of total allocated ARRs), leaving 56,459 MW of ARRs outstanding. For the 2010 to 2011 planning period, there had been 61,793 MW (45.6 percent of total demand) bid in Stage 1A 27,850 MW (20.5 percent of total demand) bid in Stage 1B and 45,971 MW (33.9 percent of total demand) bid in Stage 2. Of 135,614 MW in total ARR requests, 61,793 MW were allocated in Stage 1A and 27,850 MW were allocated in Stage 1B while 12,200 MW were allocated in Stage 2 for a total of 101,842 MW (75.1 percent) allocated. There were 46,017 MW or 54.7 percent of the allocated ARRs converted into FTRs. ARR holders did not relinquish any ARRs for the 2010 to 2011 or the 2011 to 2012 planning period.

On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period.

Table 12-31 separately lists the ARR volume for the ATSI Control Zone, which is included in the 2011 to 2012 ARR allocation volume in Table 12-30. Table 12-32 lists the directly allocated FTR volume for the 2011 to 2012 planning period for the ATSI Control Zone, which is not included in the data in Table 12-30 and Table 12-31.

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders will receive $947.3 million in credits from the Annual FTR Auction during the 2011 to 2012 planning period, with an average hourly ARR credit of $1.05 per MW. During the comparable 2010 to 2011 planning period, ARR holders received $1,028.8 million in ARR credits, with an average hourly ARR credit of $1.15 per MW.

Table 12-33 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2010 to 2011 and the 2011 to 2012 (through December 31, 2011) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2011 to 2012 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $104.5 million in auction net revenue through December 31, 2011, above the amount needed to pay 100 percent of ARR target allocations. The entire 2010 to 2011 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $45.5 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 12-30 Annual ARR allocation volume: Planning periods 2010 to 2011 and 2011 to 2012

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2010/2011	1A	0	8,862	61,793	61,793	100.0%	0	0.0%
	1B	1	3,885	27,850	27,850	100.0%	0	0.0%
	2	2	1,901	15,333	4,160	27.1%	11,173	72.9%
		3	1,374	15,321	4,167	27.2%	11,154	72.8%
		4	1,247	15,317	3,872	25.3%	11,445	74.7%
		Total	4,522	45,971	12,199	26.5%	33,772	73.5%
	Total		17,269	135,614	101,842	75.1%	33,772	24.9%
2011/2012	1A	0	12,654	64,160	64,160	100.0%	0	0.0%
	1B	1	7,660	27,325	22,208	81.3%	5,117	18.7%
	2	2	3,498	20,321	3,072	15.1%	17,249	84.9%
		3	2,593	18,538	6,653	35.9%	11,885	64.1%
		4	2,080	18,194	6,383	35.1%	11,811	64.9%
		Total	8,171	57,053	16,108	28.2%	40,945	71.8%
	Total		28,485	148,538	102,476	69.0%	46,062	31.0%

Table 12-31 ARR volume for ATSI Control Zone: 2011 to 2012 planning period[57]

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	1,309	5,434	2,770	51%	2,663	49%

Table 12-32 Direct allocation of FTR volume for ATSI Control Zone: 2011 to 2012 planning period[58]

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	114	7,750	4,189	54%	3,561	46%

Table 12-33 ARR revenue adequacy (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012

	2010/2011	2011/2012
Total FTR auction net revenue	$1,074.3	$1,051.8
Annual FTR Auction net revenue	$1,049.8	$1,029.6
Monthly Balance of Planning Period FTR Auction net revenue*	$24.5	$22.1
ARR target allocations	$1,028.8	$947.3
ARR credits	$1,028.8	$947.3
Surplus auction revenue	$45.5	$104.5
ARR payout ratio	100%	100%
FTR payout ratio*	85.0%	84.9%

* Shows twelve months for 2010/2011 and seven months ended 31-Dec-11 for 2011/2012

57 The 2011 to 2012 ARR volume data in Table 12-31 are included in the 2011 to 2012 ARR allocation data in Table 12-30.

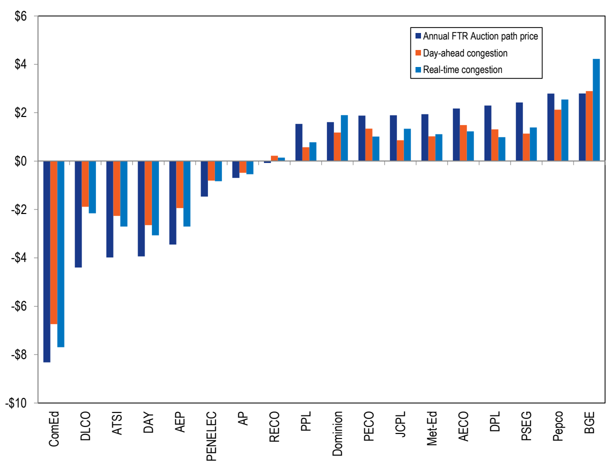
58 The 2011 to 2012 directly allocated FTR volume data in Table 12-32 are not included in ARR allocation data in Table 12-30.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-16 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2011 to 2012 planning period through December 31, 2011. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $1.88 per MW in the Annual FTR Auction and that about $1.34 per MW of day-ahead congestion and $1.02 per MW of real-time congestion existed between the Western Hub and the PECO Control Zone. The data shows that congestion costs, approximated in this way, were positive for most control zones located east of the Western Hub while congestion costs were negative and were more negative than the price of FTRs for control zones that are located west of that Hub.

Figure 12-16 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2011 to 2012 through December 31, 2011



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the balancing energy market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 12-34. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[59] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the ARR credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the cleared price for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 85.0 percent of the target allocation for the 2010 to 2011 planning period.

The "Congestion" column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self scheduled FTRs. The last column shows the difference between the total

59 For Table 12-34 through Table 12-36, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

revenue and the congestion for each ARR control zone sink.

Data shown are for the 2010 to 2011 planning period summed by ARR control zone sink. For example, the table shows that for the 2010 to 2011 planning period, ARRs allocated to the AEP Control Zone received a total of $167.4 million in revenue which was the sum of $8.9 million in ARR credits and $158.5 million in credits for self scheduled FTRs. This total revenue was $13.3 million more than the congestion costs of $154.1 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the AEP Control Zone that held ARRs or self scheduled FTRs.

Table 12-34 ARR and self scheduled FTR congestion offset by control zone: Planning period 2010 to 2011[60]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$5,622,487	$1,343,102	$6,965,589	$50,197,949	($43,232,360)	13.9%
AEP	$8,853,266	$158,525,251	$167,378,517	$154,078,263	$13,300,254	>100%
AP	$35,547,112	$309,621,694	$345,168,806	$93,793,206	$251,375,600	>100%
BGE	$29,986,713	$4,699,497	$34,686,210	$57,667,097	($22,980,887)	60.1%
ComEd	$82,312,055	$0	$82,312,055	($445,029,277)	$527,341,332	>100%
DAY	$3,657,086	$2,458,208	$6,115,294	$1,343,413	$4,771,881	>100%
DLCO	$5,052,309	$0	$5,052,309	$15,986,068	($10,933,759)	31.6%
Dominion	$4,991,988	$218,489,082	$223,481,070	$52,277,661	$171,203,409	>100%
DPL	$11,862,147	$1,710,585	$13,572,732	$69,885,719	($56,312,987)	19.4%
External	$17,922,362	$3,848,221	$21,770,583	$31,670,378	($9,899,795)	68.7%
JCPL	$15,966,799	$3,576,591	$19,543,390	$81,656,204	($62,112,814)	23.9%
Met-Ed	$13,272,652	$839,385	$14,112,037	$46,306,545	($32,194,508)	30.5%
PECO	$1,707,188	$41,316,229	$43,023,417	$13,485,128	$29,538,289	>100%
PENELEC	$23,696,177	$15,555	$23,711,732	$65,814,675	($42,102,943)	36.0%
Pepco	$20,673,905	$2,127,390	$22,801,295	$141,816,079	($119,014,784)	16.1%
PPL	$20,247,335	$6,027,176	$26,274,511	$121,317,654	($95,043,143)	21.7%
PSEG	$38,443,990	$8,904,604	$47,348,594	$29,296,535	$18,052,059	>100%
RECO	$93,249	$0	$93,249	$4,303,141	($4,209,892)	2.2%
Total	$339,908,820	$763,502,571	$1,103,411,391	$585,866,438	$517,544,953	>100%

During the 2010 to 2011 planning period, congestion costs associated with the 102,046 MW of allocated ARRs were $585.9 million. As Table 12-10 indicates, 55,732 MW of ARRs were converted into FTRs through the self scheduling option, with 46,314 MW remaining as ARRs. The 46,314 MW of remaining ARRs provided $339.9 million of ARR credits, while the self scheduled FTRs provided $763.5 million of revenue. Total congestion was fully offset by the combination of ARRs and self scheduled FTRs (Table 12-34). The effectiveness of ARRs as an offset depends on the ARR values, FTR values for self scheduled FTRs, congestion patterns in the Day-Ahead Energy Market and the balancing energy market, and the FTR payout ratio.

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 12-35 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2010 to 2011 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions, and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 85.0 percent of the target allocation for the 2010 to 2011 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control

60 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the Balancing Energy Market in each control zone.[61] The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $308.4 million in ARR credits and $323.6 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $266.8 million, the total ARR and FTR offset was $365.1 million. The total value of the ARRs and FTRs was $92.8 million higher than the $272.4 million of congestion in the Day-Ahead Energy Market and the Balancing Energy Market.

The results in Table 12-36 indicate that the value of ARRs and FTRs together offset 97.3 percent of total congestion costs. During the 2010 to 2011 planning period, the 101,843 MW of cleared ARRs produced $1,029.3 million of ARR credits while the total of all FTR credits was $1,431.9 million. When calculating the total ARR and FTR offset, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the sum of the FTR auction revenues, which was $1,097.8 million for the 2010 to 2011 planning period. The value of ARRs and FTRs was $1,363.3 million after accounting for costs, which is less than the $1,406.1 million of congestion in the Day-Ahead Energy Market and the Balancing Energy Market.

Table 12-36 shows that for the 2010 to 2011 planning period, the total value of the ARR and FTR positions was $45.4 million less than the total congestion within PJM.[62] All ARRs and FTRs offset 97.3 percent of the total congestion costs in the Day-Ahead Energy Market and the Balancing Energy Market within PJM. For the first seven months of the 2011 to 2012 planning period, the FTR payout ratio was 84.9 percent of the target allocation. All ARRs and FTRs covered greater than 100 percent of the total congestion costs within PJM for the first seven months of the 2011 to 2012 planning period. The total value of the ARR and FTR positions was greater than the cost of congestion by $44.2 million.

61 The total zonal congestion numbers were calculated as of March 2, 2012 and may change as a result of continued PJM billing updates. The total zonal congestion differs from the March 2, 2012 PJM total congestion by $4.2 Million, or 0.3 percent (.003).

62 The numbers presented here are PJM's total congestion costs for the 2010-2011 planning year and the first seven months of the 2011-2012 planning year, calculated as of March 2, 2012.

Table 12-35 ARR and FTR congestion offset by control zone: Planning period 2010 to 2011

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$6,095,482	$15,356,788	$8,369,233	$13,083,037	$34,090,353	($21,007,316)	38.4%
AEP	$194,446,396	$194,595,085	$191,920,958	$197,120,523	$175,041,297	$22,079,227	>100%
AP	$308,392,416	$323,569,671	$266,825,782	$365,136,305	$272,379,630	$92,756,674	>100%
BGE	$33,678,997	$76,071,503	$47,988,952	$61,761,548	$83,727,088	($21,965,540)	73.8%
ComEd	$91,566,097	$104,050,751	$81,016,415	$114,600,433	$266,104,165	($151,503,732)	43.1%
DAY	$5,788,157	$2,228,889	$1,857,768	$6,159,278	$5,209,352	$949,926	>100%
DLCO	$5,052,309	$4,342,645	($4,464,852)	$13,859,806	$269,563,349	($255,703,542)	5.1%
Dominion	$176,257,284	$255,309,914	$183,744,171	$247,823,027	$53,782,364	$194,040,663	>100%
DPL	$12,954,039	$28,003,826	$21,098,243	$19,859,622	$22,397,356	($2,537,734)	88.7%
External	$20,706,621	($4,725,192)	($7,470,423)	$23,451,852	($25,134,091)	$48,585,943	>100%
JCPL	$18,916,958	$50,076,625	$22,815,912	$46,177,671	$63,099,463	($16,921,792)	73.2%
Met-Ed	$13,935,697	$18,983,528	$8,126,867	$24,792,358	$3,088,074	$21,704,285	>100%
PECO	$23,365,352	$62,384,191	$30,955,754	$54,793,789	($4,607,904)	$59,401,692	>100%
PENELEC	$23,704,470	$61,042,705	$30,722,474	$54,024,701	$91,672,220	($37,647,520)	58.9%
Pepco	$22,895,504	$126,337,038	$124,122,586	$25,109,956	$92,132,782	($67,022,825)	27.3%
PPL	$27,383,200	$29,847,535	$17,822,265	$39,408,470	$730,025	$38,678,445	>100%
PSEG	$44,042,817	$86,676,270	$73,683,481	$57,035,606	($4,896,944)	$61,932,550	>100%
RECO	$93,249	($2,241,262)	($1,299,731)	($848,282)	$3,487,775	($4,336,057)	0.0%
Total	$1,029,275,045	$1,431,910,509	$1,097,835,855	$1,363,349,699	$1,401,866,354	($38,516,655)	97.3%

Table 12-36 ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012[63]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2010/2011	$1,029,275,045	$1,431,910,509	$1,097,835,855	$1,363,349,699	$1,401,866,354	($38,516,655)	97.3%
2011/2012*	$574,710,238	$672,731,759	$639,143,012	$608,298,984	$564,122,663	$44,176,321	>100%

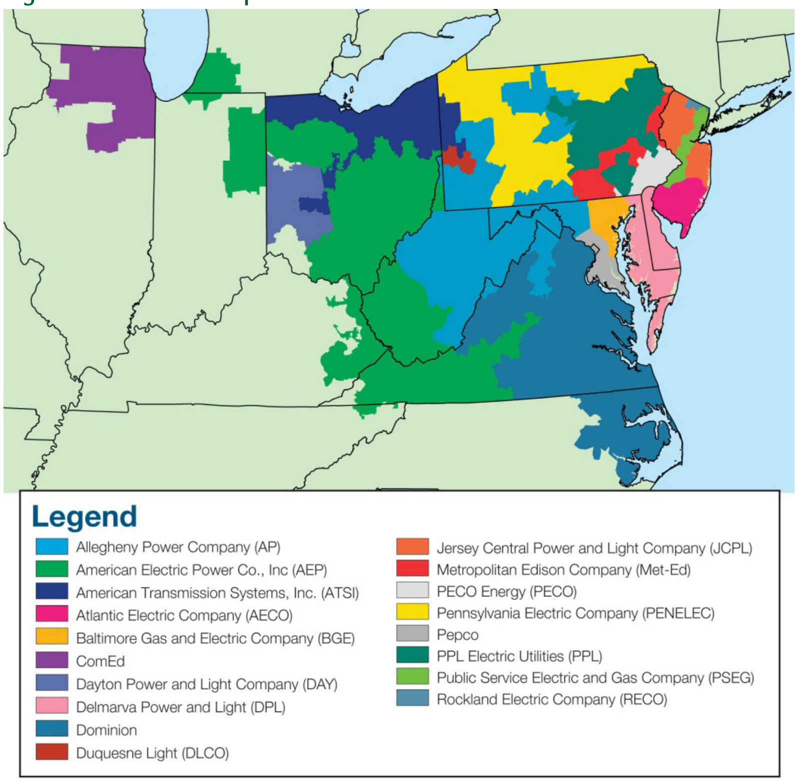
* Shows seven months ended 31-Dec-11

63 The FTR credits do not include after-the-fact adjustments. For the 2011 to 2012 planning period, the ARR credits were the total credits allocated to all ARR holders for the first seven months (June through December 2011) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

PJM Geography

During 2011, the PJM geographic footprint encompassed 18 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 18 control zones[1,2]



Analysis of 2011 market results requires comparison to 2010 and certain other prior years. During calendar year 2011, PJM integrated the ATSI Control Zone. During calendar years 2006 through 2010 the PJM footprint was stable. During calendar years 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[3]

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[4] and the Allegheny Power Company (AP) Control Zone.[5]
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[6]
- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.
- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011[7] during which PJM was comprised of the Phase 5 elements plus the ATSI

1 On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM.

2 On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone was integrated into PJM. This report covers calendar year 2011, so this figure does not include results from the DEOK Control Zone.

3 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

4 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

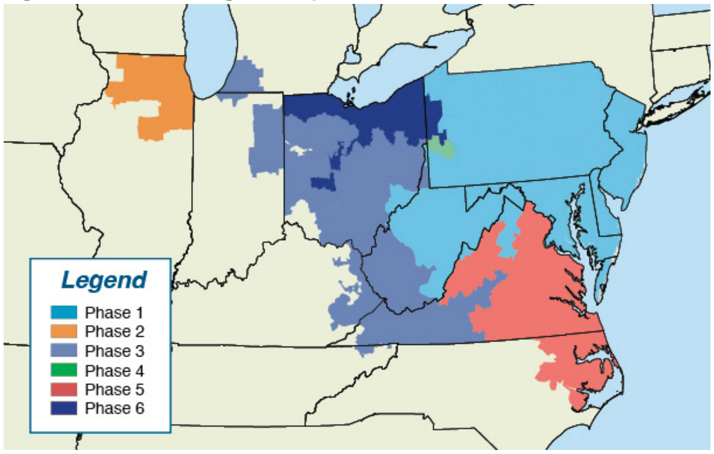
5 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

6 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

7 On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone joined the PJM footprint. This report covers calendar year 2011, so it does not include results from the DEOK Control Zone.

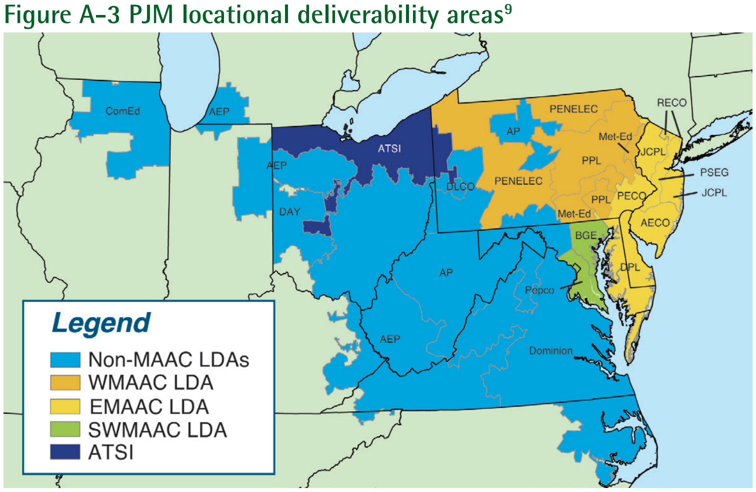
Control Zone which was integrated into PJM on June 1, 2011.

Figure A-2 PJM integration phases



A locational deliverability area (LDA)[8], defined as part of the RPM capacity market, is a Control Zone or part of a Control Zone within PJM with defined internal generation and defined transmission capability to import capacity in the RPM design.

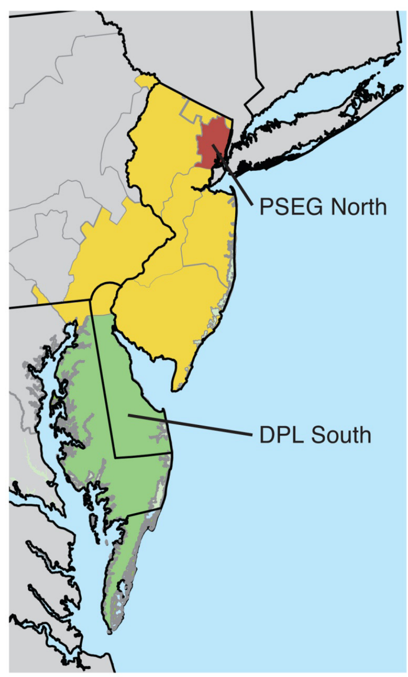
Figure A-3 PJM locational deliverability areas[9]



In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal generation without the purchase of out of merit capacity within the LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South



8 OATT Attachment DD § 2.38.

9 The ATSI Control Zone integration into PJM was effective beginning with the 2011/2012 delivery year. The ATSI Control Zone is considered a non-MAAC LDA.

PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve Accounting Rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM

Energy Market

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for the calendar years 2007 to 2011.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005 and the ATSI Control Zone in 2011 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2011 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 22.2 percent higher than off-peak load in 2011. Average load during on-peak hours in 2011 was 3.8 percent higher than in 2010. Off-peak load in 2011 was 3.6 percent higher than in 2010 (Table C-3).

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted average LMP. Differences in simple average LMP measure the change in reported price. (Simple average LMP will be referred to as average LMP.) Differences in load-weighted average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost-adjusted, load-weighted average LMP measure the change in reported price actually paid by load after accounting for the change in price that reflects changes in fuel prices.[3]

Any Load Serving Entity (LSE) may request to settle at a bus LMP or aggregate LMP per rules in PJM Manual 27. The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly individual load bus contribution to the total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[4]

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for the calendar years 2007 to 2011. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

1 The definitions of load are discussed in the *Technical Reference for PJM Markets*, Section 5, "Load Definitions."

2 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

3 See the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price."

4 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), Section 2, pp. 20.

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	859	21.63%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.42%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,177	47.85%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,257	62.20%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	721	82.12%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	493	87.75%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%
> 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	31	100.00%

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2011

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96
2010	72,186	88,066	1.22	70,318	85,435	1.21	12,942	13,753	1.06
2011	74,810	91,408	1.22	72,657	87,930	1.21	12,978	14,836	1.14

Table C-3 Multiyear change in load: Calendar years 1998 to 2011

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.8%)	(4.1%)	0.7%	(4.8%)	(4.2%)	0.6%	(4.0%)	(6.1%)	(2.2%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.4%	(0.3%)	18.5%	30.7%	10.3%
2011	3.6%	3.8%	0.2%	3.3%	2.9%	(0.4%)	0.3%	7.9%	7.6%

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	56	0.64%	94	1.07%	117	1.34%	65	0.74%	66	0.75%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
> $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted Average LMP

Table C-5 shows load-weighted, average real-time LMP for 2010 and 2011 during off-peak and on-peak periods.

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up between 80 percent and 90 percent of marginal cost on average, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[5] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2010 and 2011, the load-weighted LMP for 2011 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2010. The fuel cost adjusted, load-weighted LMP for 2011 is compared to the load-weighted LMP for 2010.[6]

Table C-6 shows the real-time, load-weighted, average LMP for 2011 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2011 for on-peak and off-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2011 on-peak hours was 6.3 percent lower than the load-weighted, average LMP for 2010 on-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2011 off-peak hours was 9.1 percent lower than the load-weighted, average LMP for 2010 off-peak hours. The mix of fuel types and costs in 2011 resulted in higher prices in 2011 than would have occurred if fuel prices had remained at their 2010 levels.

PJM Real-Time, Load-Weighted Average LMP during Constrained Hours

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2010 and 2011.[7]

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2010 to 2011

	2010			2011			Difference 2010 to 2011		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$39.88	$56.25	1.41	$37.28	$54.07	1.45	(6.5%)	(3.9%)	2.8%
Median	$33.09	$45.28	1.37	$32.37	$41.26	1.27	(2.2%)	(8.9%)	(6.8%)
Standard deviation	$23.01	$31.48	1.37	$20.01	$40.74	2.04	(13.1%)	29.4%	48.8%

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2011

	2010 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$56.25	$52.73	(6.3%)
Off Peak	$39.88	$36.25	(9.1%)

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2010 to 2011

	2010	2011	Difference
Average	$49.56	$47.36	(4.4%)
Median	$39.85	$37.05	(7.0%)
Standard deviation	$29.83	$34.90	17.0%

5 See the *2011 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-15, "Type of fuel used (By marginal units): Calendar year 2011."

6 See the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2010 and 2011.

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2010 to 2011

	2010			2011		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$39.37	$49.56	25.9%	$35.14	$47.36	34.8%
Median	$35.34	$39.85	12.8%	$33.21	$37.05	11.6%
Standard deviation	$18.46	$29.83	61.6%	$15.69	$34.90	122.4%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2010 and 2011.

Table C-9 PJM real-time constrained hours: Calendar years 2010 to 2011

	2010 Constrained Hours	2011 Constrained Hours	Total Hours
Jan	598	678	744
Feb	563	518	672
Mar	576	578	743
Apr	618	655	720
May	592	590	744
Jun	645	622	720
Jul	667	630	744
Aug	633	658	744
Sep	695	687	720
Oct	705	717	744
Nov	653	641	721
Dec	722	669	744
Avg	639	637	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2011 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2011 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2007 to 2011. Together the tables show the frequency distribution by hours for the two markets. In the Real-Time Energy Market, prices reached a high for the year of $770.58 per MWh on May 31, 2011, in the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $346.82 per MWh on June 8, 2011, in the hour ending 1700 EPT.

Off-Peak and On-Peak, Day-Ahead and Real-Time, Average LMP

Table C-11 shows PJM average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2011. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in calendar year 2011 during the on-peak and off-peak hours.

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2011

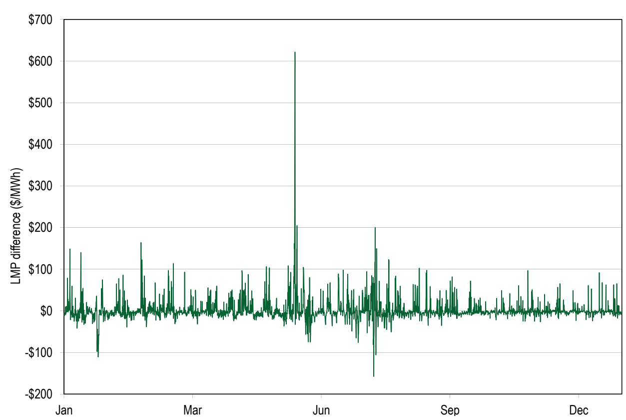


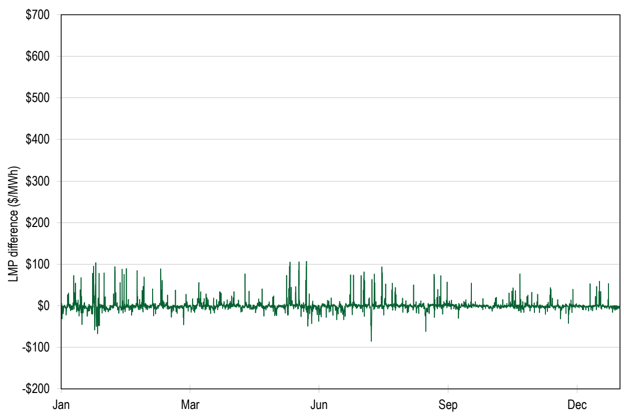
Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%
>$300	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%

Table C-11 Off-peak and on-peak, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$35.61	$50.45	1.42	$35.56	$51.20	1.44	(0.1%)	1.5%	1.6%
Median	$32.43	$44.56	1.37	$31.58	$40.25	1.27	(2.6%)	(9.7%)	(7.2%)
Standard deviation	$12.44	$24.60	1.98	$18.07	$36.11	2.00	45.3%	46.8%	1.0%

Figure C-2 Hourly real-time average LMP minus day-ahead average LMP (Off-peak hours): Calendar year 2011



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in calendar year 2011.

Table C-12 On-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$57.01	$57.22	$0.21	0.37%
AEP	$45.90	$45.70	($0.20)	(0.45%)
AP	$50.60	$50.85	$0.24	0.48%
BGE	$46.98	$46.85	($0.14)	(0.29%)
ComEd	$58.02	$59.24	$1.22	2.06%
DAY	$41.48	$41.42	($0.06)	(0.14%)
DLCO	$56.88	$56.84	($0.04)	(0.06%)
Dominion	$45.93	$46.16	$0.23	0.50%
DPL	$53.87	$54.63	$0.76	1.39%
JCPL	$46.09	$46.50	$0.41	0.88%
Met-Ed	$56.40	$57.51	$1.12	1.94%
PECO	$54.32	$55.19	$0.87	1.58%
PENELEC	$56.30	$55.88	($0.42)	(0.75%)
Pepco	$50.44	$51.17	$0.73	1.43%
PPL	$56.45	$56.47	$0.02	0.03%
PSEG	$54.17	$55.48	$1.31	2.37%
RECO	$57.41	$58.27	$0.87	1.49%

Table C-13 Off-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2011

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$39.88	$39.13	($0.76)	(1.93%)
AEP	$33.58	$33.23	($0.35)	(1.06%)
AP	$36.30	$35.99	($0.32)	(0.89%)
BGE	$32.71	$32.65	($0.06)	(0.19%)
ComEd	$40.51	$40.27	($0.23)	(0.58%)
DAY	$26.46	$26.22	($0.24)	(0.91%)
DLCO	$40.12	$39.04	($1.08)	(2.77%)
Dominion	$33.51	$33.17	($0.34)	(1.02%)
DPL	$39.14	$39.19	$0.05	0.13%
JCPL	$32.61	$32.43	($0.19)	(0.57%)
Met-Ed	$39.91	$39.05	($0.85)	(2.19%)
PECO	$38.40	$37.66	($0.75)	(1.98%)
PENELEC	$39.29	$38.44	($0.86)	(2.23%)
Pepco	$36.12	$35.79	($0.33)	(0.92%)
PPL	$39.85	$39.38	($0.48)	(1.21%)
PSEG	$38.28	$37.43	($0.85)	(2.26%)
RECO	$40.39	$39.36	($1.03)	(2.62%)

PJM Day-Ahead and Real-Time, Average LMP during Constrained Hours

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2011.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2011

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	678	744
Feb	672	518	672
Mar	743	578	743
Apr	720	655	720
May	744	590	744
Jun	720	622	720
Jul	744	630	744
Aug	744	658	744
Sep	720	687	720
Oct	744	717	744
Nov	721	641	721
Dec	744	669	744
Avg	730	637	730

Table C-15 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-15 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2011

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$0.00	$42.52	NA	$33.88	$44.15	30.3%
Median	$0.00	$38.13	NA	$32.21	$35.85	11.3%
Standard deviation	$0.00	$20.48	NA	$15.03	$30.32	101.7%

LMP by Zone and by Jurisdiction

Zonal Real-Time, Average LMP

Table C-16 Zonal real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$50.67	$47.56	($3.11)	(6.1%)
AEP	$38.36	$39.04	$0.67	1.8%
AP	$44.62	$42.91	($1.72)	(3.8%)
ATSI	NA	$39.24	NA	NA
BGE	$53.63	$49.11	($4.52)	(8.4%)
ComEd	$33.35	$33.30	($0.04)	(0.1%)
DAY	$38.11	$39.22	$1.11	2.9%
DLCO	$37.14	$38.98	$1.84	5.0%
Dominion	$50.94	$46.38	($4.56)	(8.9%)
DPL	$51.04	$47.33	($3.71)	(7.3%)
JCPL	$49.88	$47.65	($2.23)	(4.5%)
Met-Ed	$49.14	$45.82	($3.32)	(6.8%)
PECO	$49.11	$46.56	($2.55)	(5.2%)
PENELEC	$43.07	$42.95	($0.11)	(0.3%)
Pepco	$52.85	$47.34	($5.52)	(10.4%)
PPL	$47.75	$45.84	($1.91)	(4.0%)
PSEG	$50.97	$48.17	($2.81)	(5.5%)
RECO	$49.18	$44.28	($4.90)	(10.0%)
PJM	$44.83	$42.84	($1.99)	(4.4%)

Real-Time, Average LMP by Jurisdiction

Table C-17 Jurisdiction real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$50.10	$46.61	($3.49)	(7.0%)
Illinois	$33.35	$33.30	($0.04)	(0.1%)
Indiana	$37.45	$38.45	$1.00	2.7%
Kentucky	$38.49	$38.39	($0.10)	(0.3%)
Maryland	$53.18	$48.06	($5.11)	(9.6%)
Michigan	$37.88	$39.30	$1.42	3.8%
New Jersey	$50.60	$47.88	($2.72)	(5.4%)
North Carolina	$48.99	$45.23	($3.76)	(7.7%)
Ohio	$37.48	$39.38	$1.90	5.1%
Pennsylvania	$46.09	$44.48	($1.60)	(3.5%)
Tennessee	$39.27	$38.35	($0.92)	(2.3%)
Virginia	$49.46	$45.36	($4.10)	(8.3%)
West Virginia	$39.49	$39.72	$0.23	0.6%
District of Columbia	$53.03	$47.41	($5.62)	(10.6%)

Hub Real-Time, Average LMP

Table C-18 Hub real-time, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010	2011	Difference	Difference as Percent of 2010
AEP Gen Hub	$35.56	$37.08	$1.52	4.3%
AEP-DAY Hub	$37.57	$38.55	$0.98	2.6%
ATSI Gen Hub	NA	$38.87	$38.87	NA
Chicago Gen Hub	$32.23	$32.25	$0.02	0.1%
Chicago Hub	$33.54	$33.48	-$0.06	(0.2%)
Dominion Hub	$49.43	$45.84	($3.58)	(7.2%)
Eastern Hub	$50.98	$47.71	($3.27)	(6.4%)
N Illinois Hub	$33.09	$33.07	-$0.02	(0.1%)
New Jersey Hub	$50.46	$47.88	-$2.57	(5.1%)
Ohio Hub	$37.64	$38.58	$0.94	2.5%
West Interface Hub	$40.50	$40.57	$0.07	0.2%
Western Hub	$45.93	$43.56	($2.37)	(5.2%)

Zonal Real-Time, Load-Weighted, Average LMP

Table C-19 Zonal real-time, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-39)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$57.02	$53.11	($3.91)	(6.9%)
AEP	$40.43	$40.92	$0.49	1.2%
AP	$47.63	$45.49	($2.14)	(4.5%)
ATSI	NA	$42.09	NA	NA
BGE	$59.19	$54.29	($4.91)	(8.3%)
ComEd	$36.21	$36.20	($0.00)	(0.0%)
DAY	$40.51	$41.78	$1.28	3.2%
DLCO	$39.41	$41.31	$1.90	4.8%
Dominion	$56.08	$50.59	($5.49)	(9.8%)
DPL	$56.51	$52.20	($4.31)	(7.6%)
JCPL	$56.00	$53.48	($2.53)	(4.5%)
Met-Ed	$53.47	$49.51	($3.96)	(7.4%)
PECO	$53.60	$50.83	($2.78)	(5.2%)
PENELEC	$45.17	$45.12	($0.05)	(0.1%)
Pepco	$58.16	$51.84	($6.31)	(10.9%)
PPL	$51.50	$49.31	($2.20)	(4.3%)
PSEG	$55.78	$52.68	($3.10)	(5.6%)
RECO	$54.85	$49.66	($5.19)	(9.5%)
PJM	$48.35	$45.94	($2.41)	(5.0%)

Real-Time, Load-Weighted, Average LMP by Jurisdiction

Table C-20 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-40)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$55.09	$51.13	($3.96)	(7.2%)
Illinois	$36.21	$36.20	($0.00)	(0.0%)
Indiana	$39.06	$40.12	$1.06	2.7%
Kentucky	$40.96	$40.41	($0.55)	(1.3%)
Maryland	$58.86	$52.99	($5.86)	(10.0%)
Michigan	$40.23	$41.60	$1.37	3.4%
New Jersey	$56.00	$52.91	($3.09)	(5.5%)
North Carolina	$53.80	$49.20	($4.60)	(8.6%)
Ohio	$39.47	$41.54	$2.07	5.3%
Pennsylvania	$49.49	$47.65	($1.84)	(3.7%)
Tennessee	$41.99	$40.27	($1.73)	(4.1%)
Virginia	$54.24	$49.22	($5.02)	(9.3%)
West Virginia	$41.72	$41.56	($0.15)	(0.4%)
District of Columbia	$57.36	$50.88	($6.47)	(11.3%)

Zonal Day-Ahead, Average LMP

Table C-21 Zonal day-ahead, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$50.44	$47.86	($2.58)	(5.1%)
AEP	$38.30	$39.32	$1.02	2.7%
AP	$44.42	$42.96	($1.46)	(3.3%)
ATSI	NA	$39.34	NA	NA
BGE	$53.24	$48.66	($4.58)	(8.6%)
ComEd	$33.37	$33.46	$0.09	0.3%
DAY	$37.97	$39.29	$1.32	3.5%
DLCO	$37.84	$38.89	$1.05	2.8%
Dominion	$51.16	$46.00	($5.16)	(10.1%)
DPL	$50.80	$47.93	($2.87)	(5.7%)
JCPL	$50.21	$47.59	($2.62)	(5.2%)
Met-Ed	$48.98	$45.82	($3.17)	(6.5%)
PECO	$49.58	$47.21	($2.37)	(4.8%)
PENELEC	$43.94	$42.79	($1.15)	(2.6%)
Pepco	$52.94	$47.58	($5.36)	(10.1%)
PPL	$47.67	$45.68	($1.99)	(4.2%)
PSEG	$50.89	$48.32	($2.57)	(5.1%)
RECO	$49.68	$45.80	($3.88)	(7.8%)
PJM	$44.57	$42.52	($2.05)	(4.6%)

Day-Ahead, Average LMP by Jurisdiction

Table C-22 Jurisdiction day-ahead, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$49.74	$47.10	($2.64)	(5.3%)
Illinois	$33.37	$33.46	$0.09	0.3%
Indiana	$37.46	$38.51	$1.05	2.8%
Kentucky	$38.37	$38.50	$0.13	0.3%
Maryland	$53.10	$48.17	($4.93)	(9.3%)
Michigan	$37.97	$39.48	$1.51	4.0%
New Jersey	$50.63	$48.01	($2.62)	(5.2%)
North Carolina	$49.34	$44.86	($4.48)	(9.1%)
Ohio	$37.39	$39.36	$1.96	5.3%
Pennsylvania	$46.31	$44.64	($1.66)	(3.6%)
Tennessee	$39.26	$38.61	($0.66)	(1.7%)
Virginia	$49.83	$45.23	($4.60)	(9.2%)
West Virginia	$39.26	$40.27	$1.01	2.6%
District of Columbia	$53.02	$47.59	($5.42)	(10.2%)

Zonal Day-Ahead, Load-Weighted Average LMP

Table C-23 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010	2011	Difference	Difference as Percent of 2010
AECO	$57.03	$53.09	($3.94)	(6.9%)
AEP	$40.35	$41.12	$0.77	1.9%
AP	$47.08	$45.10	($1.98)	(4.2%)
ATSI	NA	$41.89	NA	NA
BGE	$58.37	$53.21	($5.16)	(8.8%)
ComEd	$35.48	$35.72	$0.24	0.7%
DAY	$40.18	$41.54	$1.36	3.4%
DLCO	$40.03	$40.98	$0.95	2.4%
Dominion	$56.08	$49.78	($6.30)	(11.2%)
DPL	$55.76	$52.62	($3.14)	(5.6%)
JCPL	$55.07	$52.22	($2.85)	(5.2%)
Met-Ed	$52.78	$48.62	($4.15)	(7.9%)
PECO	$53.63	$51.11	($2.53)	(4.7%)
PENELEC	$45.52	$44.35	($1.18)	(2.6%)
Pepco	$56.41	$51.03	($5.38)	(9.5%)
PPL	$50.92	$48.69	($2.23)	(4.4%)
PSEG	$54.99	$52.23	($2.76)	(5.0%)
RECO	$55.56	$49.96	($5.60)	(10.1%)
PJM	$47.65	$45.19	($2.46)	(5.2%)

Day-Ahead, Load-Weighted, Average LMP by Jurisdiction

Table C-24 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010	2011	Difference	Difference as Percent of 2010
Delaware	$54.23	$51.46	($2.77)	(5.1%)
Illinois	$35.48	$35.72	$0.24	0.7%
Indiana	$39.24	$40.15	$0.91	2.3%
Kentucky	$40.62	$40.41	($0.20)	(0.5%)
Maryland	$57.63	$52.23	($5.39)	(9.4%)
Michigan	$39.40	$41.37	$1.97	5.0%
New Jersey	$55.27	$52.29	($2.98)	(5.4%)
North Carolina	$54.05	$48.74	($5.31)	(9.8%)
Ohio	$39.31	$41.65	$2.34	6.0%
Pennsylvania	$49.13	$47.27	($1.86)	(3.8%)
Tennessee	$41.76	$40.58	($1.18)	(2.8%)
Virginia	$54.40	$48.65	($5.75)	(10.6%)
West Virginia	$41.58	$42.07	$0.49	1.2%
District of Columbia	$56.15	$50.57	($5.58)	(9.9%)

Zonal Price Differences

Table C-25 Zonal day-ahead and real-time average LMP (Dollars per MWh): Calendar year 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$47.86	$47.56	($0.30)	(0.6%)
AEP	$39.32	$39.04	($0.28)	(0.7%)
AP	$42.96	$42.91	($0.06)	(0.1%)
ATSI	$39.34	$39.24	($0.10)	(0.2%)
BGE	$48.66	$49.11	$0.44	0.9%
ComEd	$33.46	$33.30	($0.15)	(0.5%)
DAY	$39.29	$39.22	($0.07)	(0.2%)
DLCO	$38.89	$38.98	$0.09	0.2%
Dominion	$46.00	$46.38	$0.38	0.8%
DPL	$47.93	$47.33	($0.59)	(1.2%)
JCPL	$47.59	$47.65	$0.06	0.1%
Met-Ed	$45.82	$45.82	$0.01	0.0%
PECO	$47.21	$46.56	($0.65)	(1.4%)
PENELEC	$42.79	$42.95	$0.16	0.4%
Pepco	$47.58	$47.34	($0.25)	(0.5%)
PPL	$45.68	$45.84	$0.16	0.3%
PSEG	$48.32	$48.17	($0.15)	(0.3%)
RECO	$45.80	$44.28	($1.52)	(3.3%)
PJM	$42.52	$42.84	$0.32	0.7%

Jurisdictional Price Differences

Table C-26 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): Calendar year 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$47.10	$46.61	($0.49)	(1.0%)
Illinois	$33.46	$33.30	($0.15)	(0.5%)
Indiana	$38.51	$38.45	($0.06)	(0.2%)
Kentucky	$38.50	$38.39	($0.11)	(0.3%)
Maryland	$48.17	$48.06	($0.10)	(0.2%)
Michigan	$39.48	$39.30	($0.18)	(0.5%)
New Jersey	$48.01	$47.88	($0.13)	(0.3%)
North Carolina	$44.86	$45.23	$0.37	0.8%
Ohio	$39.36	$39.38	$0.03	0.1%
Pennsylvania	$44.64	$44.48	($0.16)	(0.4%)
Tennessee	$38.61	$38.35	($0.25)	(0.7%)
Virginia	$45.23	$45.36	$0.13	0.3%
West Virginia	$40.27	$39.72	($0.55)	(1.4%)
District of Columbia	$47.59	$47.41	($0.18)	(0.4%)

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[8] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

8 See OA Schedule 1, § 6.4.2

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[9] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-27 through Table C-30 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

Table C-27 Average day-ahead, offer-capped units: Calendar years 2007 to 2011[10]

	2007		2008		2009		2010		2011	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.2	0.0%	0.5	0.0%	0.7	0.1%	0.6	0.1%	0.1	0.0%
Feb	0.8	0.1%	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.0	0.0%
Mar	0.9	0.1%	0.0	0.0%	0.6	0.1%	0.3	0.0%	0.1	0.0%
Apr	0.2	0.0%	0.2	0.0%	0.0	0.0%	0.8	0.1%	0.3	0.0%
May	0.2	0.0%	0.6	0.1%	0.1	0.0%	1.2	0.1%	0.1	0.0%
Jun	0.8	0.1%	1.5	0.1%	0.3	0.0%	2.0	0.2%	0.0	0.0%
Jul	0.6	0.1%	1.7	0.2%	0.0	0.0%	2.8	0.3%	0.2	0.0%
Aug	1.0	0.1%	0.2	0.0%	0.4	0.0%	0.5	0.0%	0.3	0.0%
Sep	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.5	0.0%	0.3	0.0%
Oct	0.8	0.1%	0.4	0.0%	0.1	0.0%	0.3	0.0%	0.0	0.0%
Nov	0.0	0.0%	0.5	0.0%	0.0	0.0%	0.3	0.0%	0.2	0.0%
Dec	0.1	0.0%	1.3	0.1%	0.3	0.0%	0.0	0.0%	0.0	0.0%

Table C-28 Average day-ahead, offer-capped MW: Calendar years 2007 to 2011[11]

	2007		2008		2009		2010		2011	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	23	0.0%	16	0.0%	98	0.1%	50	0.1%	9	0.0%
Feb	57	0.1%	11	0.0%	30	0.0%	29	0.0%	0	0.0%
Mar	86	0.1%	2	0.0%	47	0.1%	17	0.0%	13	0.0%
Apr	11	0.0%	31	0.0%	0	0.0%	98	0.1%	33	0.0%
May	38	0.0%	15	0.0%	9	0.0%	117	0.1%	14	0.0%
Jun	28	0.0%	91	0.1%	42	0.0%	129	0.1%	4	0.0%
Jul	45	0.0%	110	0.1%	0	0.0%	143	0.1%	20	0.0%
Aug	58	0.1%	35	0.0%	35	0.0%	61	0.1%	45	0.0%
Sep	14	0.0%	66	0.1%	10	0.0%	34	0.0%	38	0.0%
Oct	77	0.1%	39	0.0%	3	0.0%	26	0.0%	1	0.0%
Nov	4	0.0%	47	0.1%	0	0.0%	23	0.0%	23	0.0%
Dec	4	0.0%	187	0.2%	29	0.0%	0	0.0%	0	0.0%

9 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."
10 The version of this table in the *2010 State of the Market Report for PJM* incorrectly mapped the results to months for the years 2009 and 2010.
11 The version of this table in the *2010 State of the Market Report for PJM* incorrectly mapped the results to months for the years 2009 and 2010.

Table C-29 Average real-time, offer-capped units: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.2	0.1%	3.1	0.3%	2.4	0.2%	2.3	0.2%	2.8	0.3%
Feb	4.2	0.4%	2.6	0.3%	1.1	0.1%	1.9	0.2%	2.3	0.2%
Mar	1.9	0.2%	2.7	0.3%	1.8	0.2%	2.5	0.2%	1.6	0.1%
Apr	1.3	0.1%	3.1	0.3%	1.8	0.2%	3.2	0.3%	2.8	0.3%
May	1.9	0.2%	2.1	0.2%	1.0	0.1%	4.5	0.4%	2.8	0.3%
Jun	6.0	0.6%	8.7	0.8%	1.3	0.1%	7.1	0.7%	4.3	0.4%
Jul	4.4	0.4%	5.7	0.6%	1.1	0.1%	9.3	0.9%	8.0	0.7%
Aug	9.6	0.9%	2.0	0.2%	3.0	0.3%	5.8	0.5%	3.2	0.3%
Sep	5.5	0.5%	4.8	0.5%	1.6	0.1%	6.2	0.6%	6.4	0.6%
Oct	5.0	0.5%	2.5	0.2%	1.2	0.1%	3.5	0.3%	4.3	0.4%
Nov	2.9	0.3%	2.2	0.2%	0.6	0.1%	3.1	0.3%	4.1	0.4%
Dec	4.7	0.5%	2.5	0.2%	1.3	0.1%	6.3	0.6%	4.7	0.4%

Table C-30 Average real-time, offer-capped MW: Calendar years 2007 to 2011

	2007		2008		2009		2010		2011	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	50	0.1%	99	0.1%	158	0.2%	124	0.1%	197	0.2%
Feb	125	0.1%	92	0.1%	92	0.1%	117	0.1%	125	0.2%
Mar	142	0.2%	117	0.2%	147	0.2%	216	0.3%	167	0.2%
Apr	48	0.1%	125	0.2%	151	0.2%	251	0.4%	267	0.4%
May	68	0.1%	59	0.1%	64	0.1%	337	0.5%	291	0.4%
Jun	190	0.2%	415	0.5%	103	0.1%	382	0.4%	330	0.4%
Jul	160	0.2%	202	0.2%	74	0.1%	473	0.5%	436	0.4%
Aug	314	0.3%	99	0.1%	137	0.2%	253	0.3%	245	0.3%
Sep	218	0.3%	182	0.2%	95	0.1%	378	0.5%	436	0.5%
Oct	153	0.2%	177	0.3%	105	0.2%	345	0.5%	319	0.4%
Nov	104	0.1%	157	0.2%	60	0.1%	382	0.5%	324	0.4%
Dec	146	0.2%	211	0.3%	128	0.2%	538	0.6%	330	0.4%

In order to help understand the frequency of offer capping in more detail, Table C-31 through Table C-35 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2007 through 2011.

Table C-31 Offer-capped unit statistics: Calendar year 2007

	2007 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table C-32 Offer-capped unit statistics: Calendar year 2008

	2008 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-33 Offer-capped unit statistics: Calendar year 2009

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table C-34 Offer-capped unit statistics: Calendar year 2010

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

Table C-35 Offer-capped unit statistics: Calendar year 2011

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2011, through December 31, 2011. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small. The results show that the percentage of tests where one or more suppliers pass the three pivotal supplier test increases as the number of suppliers increases and as the residual supply in the local market increases. The results also show that the percentage of tests where one or more suppliers fail the three pivotal supplier test increases as the number of suppliers decreases and the residual supply in the local market decreases.

This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours. In 2011, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, Met-Ed, PECO and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2011, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[1] The DAY, DPL, JCPL, PPL, PENELEC, Pepco and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping, and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[2] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AECO Control Zone Results

In 2011, there was only one constraint in the AECO Control Zone that occurred for more than 100 hours. Table D-1 and Table D-2 show the results of the three pivotal supplier test applied to this constraint. Table D-1 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-1 shows that all 2,977 on peak, and all 1,752 off peak tests resulted in one or more owners failing. Table D-2 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-2 shows that on an average, there was only one owner with available supply on peak and one owner off peak for the Shieldalloy - Vineland line. The three pivotal supplier test results reflect this, as all tests were failed.

1 See the Technical Reference for PJM Markets, Section 8,"Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

2 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

Table D-1 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Shieldalloy - Vineland	Peak	2,977	0	0%	2,977	100%
	Off Peak	1,752	0	0%	1,752	100%

Table D-2 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2011[3]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Shieldalloy - Vineland	Peak	11	12	1	0	1
	Off Peak	10	12	1	0	1

Table D-3 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Shieldalloy - Vineland	Peak	2,977	6	0%	0	0%	0%
	Off Peak	1,752	6	0%	0	0%	0%

Table D-4 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brues - West Bellaire	Peak	12,484	0	0%	12,484	100%
	Off Peak	10,417	0	0%	10,417	100%
Carnegie - Tidd	Peak	5,553	0	0%	5,553	100%
	Off Peak	3,035	0	0%	3,035	100%
Cloverdale	Peak	1,736	134	8%	1,696	98%
	Off Peak	2,474	106	4%	2,443	99%
Dumont - Stillwell	Peak	1,972	229	12%	1,814	92%
	Off Peak	982	142	14%	908	92%
Kammer - Ormet	Peak	2,820	0	0%	2,820	100%
	Off Peak	964	0	0%	964	100%
Ruth - Turner	Peak	2,472	0	0%	2,472	100%
	Off Peak	2,401	0	0%	2,401	100%
Wolfcreek	Peak	2,470	0	0%	2,470	100%
	Off Peak	2,777	0	0%	2,777	100%

Table D-5 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2011[4]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brues - West Bellaire	Peak	23	29	1	0	1
	Off Peak	22	34	1	0	1
Carnegie - Tidd	Peak	14	40	1	0	1
	Off Peak	12	41	1	0	1
Cloverdale	Peak	225	318	10	0	10
	Off Peak	195	269	8	0	8
Dumont - Stillwell	Peak	194	250	13	1	12
	Off Peak	143	208	12	2	10
Kammer - Ormet	Peak	34	48	1	0	1
	Off Peak	18	34	1	0	1
Ruth - Turner	Peak	23	4	1	0	1
	Off Peak	20	4	1	0	1
Wolfcreek	Peak	30	17	2	0	2
	Off Peak	32	17	2	0	2

3 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
4 Average Effective Supply was incorrectly reported in prior State of the Market Reports..

Table D-3 shows the subset of three pivotal supplier tests from Table D-1 that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for the Shieldalloy - Vineland line in the AECO zone. Only six out of 2,977 tests applied to offline, uncommitted units that were eligible for offer capping on peak. Only six out of 1,752 tests were applied to offline, uncommitted units that were eligible for offer capping off peak. None of the tests resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

AEP Control Zone Results

In 2011, there were seven constraints that occurred for more than 100 hours in the AEP Control Zone. Table D-4 and Table D-5 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. Table D-4 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-4 shows that most of the tests resulted in one or more owners failing. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-5 shows that for four of the seven constraints, the average number of owners with available supply was one.

Table D-6 shows the total tests applied for the eight constraints in the AEP zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-6 shows that four percent or fewer of the tests applied to the seven constraints in the AEP zone could have resulted in offer capping. For three of the seven constraints, none of the tests could have resulted in offer capping.

AP Control Zone Results

In 2011, there were four constraints that occurred for more than 100 hours in the AP Control Zone. Table D-7 and Table D-8 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. Table D-7 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-7 shows that most of the tests resulted in one or more owners failing. Table D-8 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-8 shows that for two of the four constraints, the average number of owners with available supply was two or fewer.

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AEP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Brues - West Bellaire	Peak	12,484	0	0%	0	0%	0%
	Off Peak	10,417	1	0%	0	0%	0%
Carnegie - Tidd	Peak	5,553	0	0%	0	0%	0%
	Off Peak	3,035	0	0%	0	0%	0%
Cloverdale	Peak	1,736	64	4%	37	2%	58%
	Off Peak	2,474	28	1%	8	0%	29%
Dumont - Stillwell	Peak	1,972	13	1%	1	0%	8%
	Off Peak	982	10	1%	1	0%	10%
Kammer - Ormet	Peak	2,820	0	0%	0	0%	0%
	Off Peak	964	0	0%	0	0%	0%
Ruth - Turner	Peak	2,472	0	0%	0	0%	0%
	Off Peak	2,401	0	0%	0	0%	0%
Wolfcreek	Peak	2,470	4	0%	1	0%	25%
	Off Peak	2,777	5	0%	0	0%	0%

Table D-7 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	3,624	0	0%	3,624	100%
	Off Peak	26	0	0%	26	100%
Belmont	Peak	5,642	0	0%	5,642	100%
	Off Peak	2,377	0	0%	2,377	100%
Mount Storm	Peak	3,316	454	14%	3,148	95%
	Off Peak	580	20	3%	576	99%
Wylie Ridge	Peak	5,909	824	14%	5,548	94%
	Off Peak	6,996	1000	14%	6,642	95%

Table D-8 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2011[5]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	36	27	2	0	2
	Off Peak	27	12	2	0	2
Belmont	Peak	28	16	1	0	1
	Off Peak	27	21	1	0	1
Mount Storm	Peak	322	478	13	1	11
	Off Peak	360	505	10	0	9
Wylie Ridge	Peak	132	126	14	1	12
	Off Peak	165	188	13	1	12

Table D-9 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bedington	Peak	3,624	5	0%	0	0%	0%
	Off Peak	26	0	0%	0	0%	0%
Belmont	Peak	5,642	3	0%	0	0%	0%
	Off Peak	2,377	0	0%	0	0%	0%
Mount Storm	Peak	3,316	91	3%	37	1%	41%
	Off Peak	580	11	2%	2	0%	18%
Wylie Ridge	Peak	5,909	115	2%	47	1%	41%
	Off Peak	6,996	145	2%	51	1%	35%

Table D-10 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Glenarm - Windy Edge	Peak	3,554	0	0%	3,554	100%
	Off Peak	1,137	0	0%	1,137	100%
Graceton - Raphael Road	Peak	5,869	2,256	38%	4,845	83%
	Off Peak	7,140	1,941	27%	6,393	90%
Northwest	Peak	2,746	430	16%	2,643	96%
	Off Peak	978	320	33%	872	89%
Riverside	Peak	2,336	0	0%	2,336	100%
	Off Peak	334	0	0%	334	100%

Table D-11 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2011[6]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Glenarm - Windy Edge	Peak	23	11	1	0	1
	Off Peak	22	14	1	0	1
Graceton - Raphael Road	Peak	77	156	10	3	7
	Off Peak	83	156	9	2	7
Northwest	Peak	71	108	9	1	8
	Off Peak	69	128	9	2	7
Riverside	Peak	30	37	1	0	1
	Off Peak	64	60	1	0	1

5 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
6 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Table D-9 shows the total tests applied for the ten constraints in the AP zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-9 shows that three percent or fewer of the tests applied to the four constraints in the AP zone could have resulted in offer capping. None of the constraints had more than one percent of its tests result in offer capping.

BGE Control Zone Results

In 2011, there were four constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-10 and Table D-11 show the results of the three pivotal supplier tests applied to the constraints in the BGE Control Zone. Table D-10 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-10 shows that for two of the four constraints, all of the tests resulted in one or more owners failing. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-11 shows that for two of the four constraints, there was only one owner, on average, with available supply to relieve the constraint, both on peak and off peak.

Table D-12 shows the total tests applied for the four constraints in the BGE zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-12 shows that two percent or fewer of the tests applied to the four constraints in the BGE zone could have resulted in offer capping and that one percent or fewer of their tests resulted in offer capping.

ComEd Control Zone Results

In 2011, there were five constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-13 and Table D-14 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. Table D-13 provides the number of tests

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Glenarm - Windy Edge	Peak	3,554	3	0%	2	0%	67%
	Off Peak	1,137	4	0%	1	0%	25%
Graceton - Raphael Road	Peak	5,869	34	1%	7	0%	21%
	Off Peak	7,140	57	1%	10	0%	18%
Northwest	Peak	2,746	13	0%	8	0%	62%
	Off Peak	978	18	2%	7	1%	39%
Riverside	Peak	2,336	16	1%	14	1%	88%
	Off Peak	334	3	1%	3	1%	100%

Table D-13 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	2,979	270	9%	2,798	94%
	Off Peak	4,743	279	6%	4,643	98%
East Frankfort - Crete	Peak	3,005	12	0%	3,000	100%
	Off Peak	5,957	13	0%	5,952	100%
Electric Jct - Nelson	Peak	915	4	0%	912	100%
	Off Peak	1,085	4	0%	1,083	100%
Nelson - Cordova	Peak	547	5	1%	546	100%
	Off Peak	183	0	0%	183	100%
Pleasant Valley - Belvidere	Peak	461	0	0%	461	100%
	Off Peak	872	0	0%	872	100%

applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-13 shows that most of the tests resulted in one or more owners failing for all five constraints. Table D-14 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was three or less for three out of five constraints.

Table D-15 shows the total tests applied for the five constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-15 shows that one percent or fewer of the tests applied to the seven constraints in the AEP zone could have resulted in offer capping.

Table D-14 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2011[7]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	156	210	10	1	9
	Off Peak	151	207	6	0	6
East Frankfort - Crete	Peak	132	155	3	0	3
	Off Peak	126	132	3	0	3
Electric Jct - Nelson	Peak	38	26	3	0	3
	Off Peak	28	24	3	0	3
Nelson - Cordova	Peak	32	32	4	0	4
	Off Peak	36	38	2	0	2
Pleasant Valley - Belvidere	Peak	10	7	1	0	1
	Off Peak	5	4	1	0	1

Table D-15 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Burnham - Munster	Peak	2,979	20	1%	14	0%	70%
	Off Peak	4,743	11	0%	2	0%	18%
East Frankfort - Crete	Peak	3,005	1	0%	0	0%	0%
	Off Peak	5,957	5	0%	0	0%	0%
Electric Jct - Nelson	Peak	915	3	0%	2	0%	67%
	Off Peak	1,085	0	0%	0	0%	0%
Nelson - Cordova	Peak	547	6	1%	2	0%	33%
	Off Peak	183	0	0%	0	0%	0%
Pleasant Valley - Belvidere	Peak	461	0	0%	0	0%	0%
	Off Peak	872	0	0%	0	0%	0%

Table D-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Crescent	Peak	2,872	0	0%	2,872	100%
	Off Peak	108	0	0%	108	100%

Table D-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2011[8]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crescent	Peak	31	32	1	0	1
	Off Peak	26	30	2	0	2

7 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
8 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

DLCO Control Zone Results

In 2011, there was only one constraint that occurred for more than 100 hours in the DLCO Control Zone. Table D-16 and Table D-17 show the results of the three pivotal supplier tests applied to the constraint in the DLCO Control Zone. Table D-16 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-16 shows that all tests resulted in one or more owners failing. Table D-17 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was one on peak and two off peak for the Crescent constraint.

Table D-18 shows the total tests applied for the Crescent constraint in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-18 shows that only 3 of the 2,980 applied tests could have resulted in offer capping and none of those tests resulted in offer capping.

Dominion Control Zone Results

In 2011, there were five constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-19 and Table D-20 show the results of the three pivotal supplier tests applied to the constraints in the Dominion Control Zone. Table D-19 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-19 shows that most of the tests resulted in one or more owners failing for all constraints. Table D-20 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was less than five on peak and off peak for all five constraints.

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Crescent	Peak	2,872	3	0%	0	0%	0%
	Off Peak	108	0	0%	0	0%	0%

Table D-19 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Chaparral - Carson	Peak	3,296	92	3%	3,255	99%
	Off Peak	1,206	49	4%	1,183	98%
Clover	Peak	9,288	12	0%	9,284	100%
	Off Peak	3,919	1	0%	3,919	100%
Danville - East Danville	Peak	4,272	1	0%	4,272	100%
	Off Peak	5,124	0	0%	5,124	100%
Halifax - Mount Laurel	Peak	2,722	0	0%	2,722	100%
	Off Peak	1,404	0	0%	1,404	100%
Hollymead - Charlottesville	Peak	2,366	0	0%	2,366	100%
	Off Peak	2,052	0	0%	2,052	100%

Table D-21 shows the total tests applied for the five constraints in the Dominion zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-21 shows that one percent or fewer of the tests applied to the five constraints in the Dominion zone could have resulted in offer capping.

Met-Ed Control Zone Results

In 2011, there was only one constraint that occurred for more than 100 hours in the Met-Ed Control Zone. Table D-22 and Table D-23 show the results of the three pivotal supplier tests applied to the constraint in the Met-Ed Control Zone. Table D-22 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-22 shows that all of tests resulted in one or more owners failing. Table D-23 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing.

Table D-24 shows the total tests applied for the one constraint in the Met-Ed zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-24 shows that one percent or fewer of the tests applied to the one constraint in the Met-Ed zone could have resulted in offer capping. Only 18 out of 2,970 on peak tests could have resulted in offer capping. Only 14 out of 2,970 on peak tests resulted in offer capping. Only 11 out of 1,153 tests applied off peak could have resulted in offer capping. All 11 of those off peak tests resulted in offer capping.

Table D-20 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2011[9]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Chaparral - Carson	Peak	93	132	5	0	5
	Off Peak	71	106	4	0	4
Clover	Peak	103	145	3	0	3
	Off Peak	92	161	2	0	2
Danville - East Danville	Peak	50	38	2	0	2
	Off Peak	53	42	2	0	2
Halifax - Mount Laurel	Peak	10	15	1	0	1
	Off Peak	9	14	1	0	1
Hollymead - Charlottesville	Peak	57	49	2	0	2
	Off Peak	91	63	2	0	2

Table D-21 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Chaparral - Carson	Peak	3,296	4	0%	1	0%	25%
	Off Peak	1,206	7	1%	0	0%	0%
Clover	Peak	9,288	67	1%	19	0%	28%
	Off Peak	3,919	21	1%	6	0%	29%
Danville - East Danville	Peak	4,272	10	0%	7	0%	70%
	Off Peak	5,124	25	0%	3	0%	12%
Halifax - Mount Laurel	Peak	2,722	0	0%	0	0%	0%
	Off Peak	1,404	0	0%	0	0%	0%
Hollymead - Charlottesville	Peak	2,366	2	0%	0	0%	0%
	Off Peak	2,052	4	0%	3	0%	75%

9 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

PECO Control Zone Results

In 2011, there were three constraints that occurred for more than 100 hours in the PECO Control Zone. Table D-25 and Table D-26 show the results of the three pivotal supplier tests applied to the constraints in the PECO Control Zone. Table D-25 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-25 shows that most of tests resulted in one or more owners failing. Table D-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For two of the three constraints, on an average, there was only one owner with available supply to relieve the constraint.

Table D-22 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cly - Collins	Peak	2,970	0	0%	2,970	100%
	Off Peak	1,153	0	0%	1,153	100%

Table D-23 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2011[10]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cly - Collins	Peak	22	12	1	0	1
	Off Peak	22	11	1	0	1

Table D-24 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Met-Ed Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cly - Collins	Peak	2,970	18	1%	14	0%	78%
	Off Peak	1,153	11	1%	11	1%	100%

Table D-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cromby	Peak	1,823	0	0%	1,823	100%
	Off Peak	565	0	0%	565	100%
Eddington - Holmesburg	Peak	5,500	3	0%	5,500	100%
	Off Peak	2,001	3	0%	2,001	100%
Emilie	Peak	4,538	0	0%	4,538	100%
	Off Peak	2,875	0	0%	2,875	100%

Table D-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2011[11]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cromby	Peak	16	16	1	0	1
	Off Peak	18	19	1	0	1
Eddington - Holmesburg	Peak	63	110	2	0	2
	Off Peak	62	102	3	0	3
Emilie	Peak	45	108	1	0	1
	Off Peak	45	118	1	0	1

10 Average Effective Supply was incorrectly reported in prior State of the Market Reports.
11 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Table D-27 shows the total tests applied for the constraints in the PECO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-27 shows that two percent or fewer of the tests applied to the constraints in the PECO zone could have resulted in offer capping. For two of the three constraints, none of the tests resulted in offer capping. For the third constraint, all 20 tests that could have resulted in offer capping did result in offer capping.

PSEG Control Zone Results

In 2011, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-28 and Table D-29 show the results of the three pivotal supplier tests applied to the constraints in the PSEG Control Zone. Table D-28 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners. Table D-28 shows that most of the tests resulted in one or more owners failing. Table D-29 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For both of the constraints, the average number of owners with available supply was three or less.

Table D-30 shows the total tests applied for the two constraints in the PSEG zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-30 shows that one percent or fewer of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The South Mahwah - Waldwick constraint had only 94 of its 13,812 applied tests that could have result in offer capping. Only 58 of the 13,812 applied tests did result in offer capping. The Sewaren - Woodbridge constraint had none of its 4,060 applied tests that could have resulted in offer capping.

Table D-27 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PECO Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Cromby	Peak	1,823	8	0%	8	0%	100%
	Off Peak	565	12	2%	12	2%	100%
Eddington - Holmesburg	Peak	5,500	1	0%	0	0%	0%
	Off Peak	2,001	1	0%	0	0%	0%
Emilie	Peak	4,538	0	0%	0	0%	0%
	Off Peak	2,875	0	0%	0	0%	0%

Table D-28 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Sewaren - Woodbridge	Peak	3,006	0	0%	3,006	100%
	Off Peak	1,054	0	0%	1,054	100%
South Mahwah - Waldwick	Peak	8,981	1	0%	8,981	100%
	Off Peak	4,831	5	0%	4,828	100%

Table D-29 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2011[12]

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Sewaren - Woodbridge	Peak	10	40	1	0	1
	Off Peak	11	22	1	0	1
South Mahwah - Waldwick	Peak	70	65	3	0	3
	Off Peak	56	55	2	0	2

Table D-30 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: Calendar year 2011

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Sewaren - Woodbridge	Peak	3,006	0	0%	0	0%	0%
	Off Peak	1,054	0	0%	0	0%	0%
South Mahwah - Waldwick	Peak	8,981	72	1%	42	0%	58%
	Off Peak	4,831	22	0%	16	0%	73%

12 Average Effective Supply was incorrectly reported in prior State of the Market Reports.

Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Market

Market participants that wish to transact energy into, out of, or through PJM in the Real-Time Energy Market are required to make their requests to PJM via the NERC Interchange Transaction Tag (NERC Tag). PJM's Enhanced Energy Scheduler (EES) software interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

All PJM interchange transactions are required to be at least 45 minutes in duration. However, PJM system operators may make adjustments that cause a transaction or interval(s) of the transaction to violate this minimum duration.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration. For a schedule to be included in PJM's day-ahead checkout process, the NERC Tag must be approved by all entities who have approval rights, and be in a status of "Implemented", by 1400 (EPT) one day prior to start of schedule. Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1200 noon (EPT) the day prior to the scheduled start time. Schedules utilizing firm point-to-point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point-to-point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[2] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation

1 The material in this section is based in part on PJM Manual M-41: Managing Interchange. See PJM. "M-41: Managing Interchange", Revision 03 (November 24, 2008).

2 For additional details see PJM. "*PJM Regional Practices document*" http://oasis.pjm.com.

by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface Pricing point (SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When EES detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to 0 MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Schedule Requirements

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be removed from the PJM Region, via dynamic scheduling of the output, to a load outside the PJM Region. An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be added to the PJM Region, via dynamic scheduling of the output, to a load inside the PJM Region. Due to the complexity of these arrangements, requesting entities must coordinate with PJM and complete several steps before a dynamic schedule can be implemented. The requesting entity is responsible for submitting a dynamic NERC Tag to match the scheduled output of the generating resource.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with price schedules, also known as dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since real-time with price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[3]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.
- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed

3 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed March 1, 2012) <http://www.nerc.com/files/IRO-006-4.pdf> (KB).

under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.
- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 below shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Day-Ahead Market

For Day-Ahead Market scheduling, EES serves only as an interface to the eMarket application. Day-Ahead Market transactions are evaluated in the Day-Ahead Market, and the results sent to EES. No checkout is performed on Day-Ahead Market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Market Schedules

Market participants can submit Day-Ahead Market schedules to the eMarket application through EES. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-Ahead Market schedules require an OASIS number to be associated upon submission.[4] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining

4 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in *Section 8: Interchange Transactions* of this report.

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2011

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199

the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[5]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[6] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[7] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW

5 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

6 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

7 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed March 1, 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

Table E-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2011 (continued)

2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562

bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[8] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

8 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed March 1, 2012) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[9] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[10] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[11] PJM continued to operate under the terms of the protocol through 2010.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City (Figure E-1). Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[12] The protocol was implemented in July 2005.

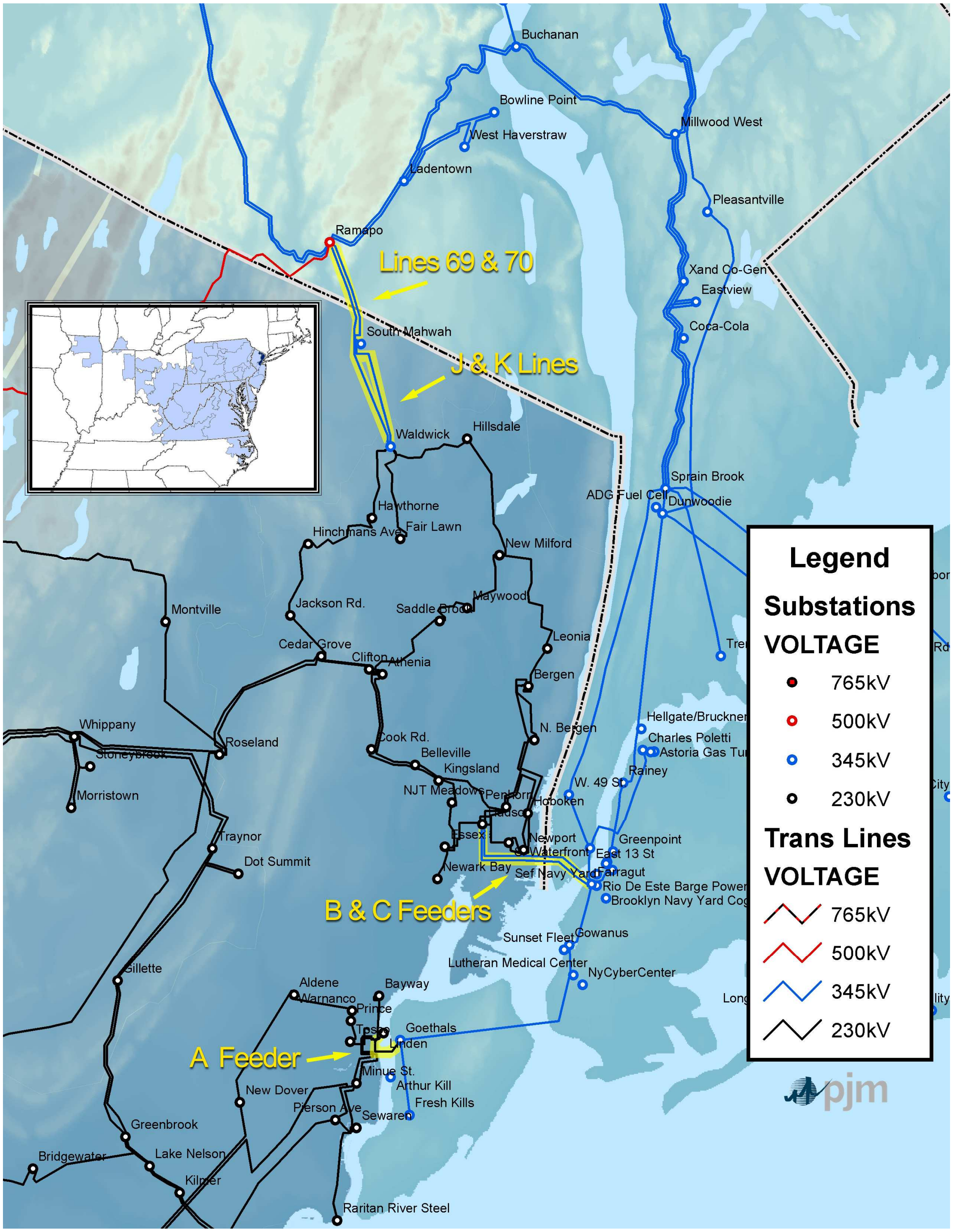
The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2011, PSE&G's revenues were greater than its congestion charges by $778,879 after adjustments (PSE&G's revenues were less than its congestion charges by $1,028,909 in 2010.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2011, Con Edison's congestion credits were $2,319,278 more than its day-ahead congestion charges (Credits had been $3,066,001 less than charges in 2010). Table E-2 shows the monthly details for both PSE&G and Con Edison.

9 111 FERC ¶ 61,228 (2005).
10 "Protest of the Consolidated Edison Company of New York, Inc.", Protest, Docket No. EL02-23-000 (January 30, 2006).
11 120 FERC ¶ 61,161
12 111 FERC ¶ 61,228 (2005).

Figure E-1 Con Edison and PSE&G wheel



The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[13]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$2,715,707 in 2011. The parties should address this issue.

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 1.2 percent of the hours in 2011.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[14] By order issued September 16, 2010, the Commission approved this settlement,[15] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[16]

13 *PJM Interconnection, L.L.C.*, Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

14 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

15 132 FERC ¶ 61,221.

16 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

Table E-2 Con Edison and PSE&G wheel settlements data: Calendar year 2011

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	($63,871)	($35)	($63,906)	($1,666,133)	$0	($1,666,133)
	Congestion Credit			$1,415			($1,666,701)
	Adjustments			$15,121			$2,588
	Net Charge			($80,442)			($2,020)
February	Congestion Charge	($67,206)	$0	($67,206)	($1,753,211)	$0	($1,753,211)
	Congestion Credit			$67			($1,754,139)
	Adjustments			$0			($288)
	Net Charge			($67,273)			$1,216
March	Congestion Charge	($304,075)	($1)	($304,076)	($2,881,691)	$0	($2,881,691)
	Congestion Credit			$230			($2,869,877)
	Adjustments			$7			($1,005)
	Net Charge			($304,313)			($10,809)
April	Congestion Charge	($870,350)	$0	($870,350)	($4,211,372)	$0	($4,211,372)
	Congestion Credit			$132			($4,211,808)
	Adjustments			$0			($909)
	Net Charge			($870,483)			$1,345
May	Congestion Charge	$132,405	($23)	$132,382	($83)	$0	($83)
	Congestion Credit			$16,949			($146,647)
	Adjustments			($6)			$1,008,034
	Net Charge			$115,439			($861,471)
June	Congestion Charge	$108,202	$0	$108,202	$246,668	$0	$246,668
	Congestion Credit			$68,480			$215,208
	Adjustments			$0			($1,152)
	Net Charge			$39,722			$32,612
July	Congestion Charge	($569,345)	$0	($569,345)	($854,018)	$0	($854,018)
	Congestion Credit			$8,094			($854,687)
	Adjustments			($1)			($800)
	Net Charge			($577,438)			$1,469
August	Congestion Charge	($358,757)	($33)	($358,790)	($538,136)	$0	($538,136)
	Congestion Credit			$41,467			($543,794)
	Adjustments			$48			($1,028)
	Net Charge			($400,306)			$6,686
September	Congestion Charge	($122,265)	($870)	($123,135)	($395,803)		($395,803)
	Congestion Credit			$5,831			($414,487)
	Adjustments			$290			($803)
	Net Charge			($129,256)			$19,488
October	Congestion Charge	($37,616)	$0	($37,616)	($454,781)	$0	($454,781)
	Congestion Credit			$88			($460,193)
	Adjustments			$131			($752)
	Net Charge			($37,835)			$6,164
November	Congestion Charge	$955	($56)	$900	$10,537	$0	$10,537
	Congestion Credit			$228			$1,541
	Adjustments			$10			($769)
	Net Charge			$661			$9,765
December	Congestion Charge	($21,216)	($1,453)	($22,669)	($82,332)	$0	($82,332)
	Congestion Credit			$3,155			($98,217)
	Adjustments			$12			($791)
	Net Charge			($25,836)			$16,676
Total	Congestion Charge	($2,173,141)	($2,471)	($2,175,611)	($12,580,355)	$0	($12,580,355)
	Congestion Credit			$146,137			($12,803,800)
	Adjustments			$15,611			$1,002,325
	Net Charge			($2,337,360)			($778,879)

Ancillary Service Markets

This appendix covers two areas related to Ancillary Service Markets: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

1 The PJM Manuals define ACE: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions--the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively." PJM. "Manual 12: Balancing Operations," Revision 23 (November 16, 2011), para. 3.1.1, "PJM Area Control Error" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), pp. 53-62.

3 See "Manual 12: Balancing Operations," Revision 23 (November 16, 2011), Section 4.5.5, pg. 49.

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units. During 2011, PJM modified its regulation rules to establish a minimum 0.1 MW capability for generating, storage and demand response units in order to qualify for regulation. PJM is currently studying significant modifications to the regulation market clearing procedure and regulation resource qualifying rules to promote new sources of regulation. Phase I implementation is expected in the late Spring of 2012. Among the changes will be implementation of real time performance evaluation designed to measure the accuracy and precision of regulation in response to the regulation signal. Another change will be the implementation of a dynamic (fast) regulation signal which regulation resources may choose to follow.

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

- Control Performance Standard 1 (CPS1) and Balancing Authority Ace Limit (BAAL) are standard metrics used to measure and report the effectiveness of ACE control. The purpose of the CPS1/BAAL standards is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.
- **CPS1.** CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute. It is intended to provide

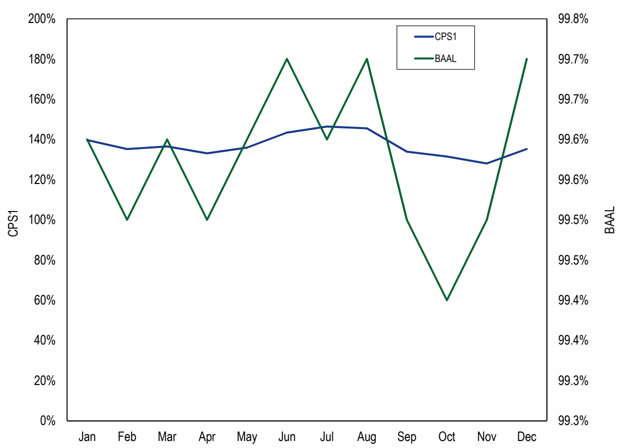
a frequency-sensitive evaluation of how well PJM meets its demand requirements with its supply resources. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which establishes a new metric, balancing authority ACE limit (BAAL). PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for both CPS1 and BAAL metrics was acceptable in calendar year 2011.

Figure F-1 PJM CPS1/BAAL performance: Calendar year 2011



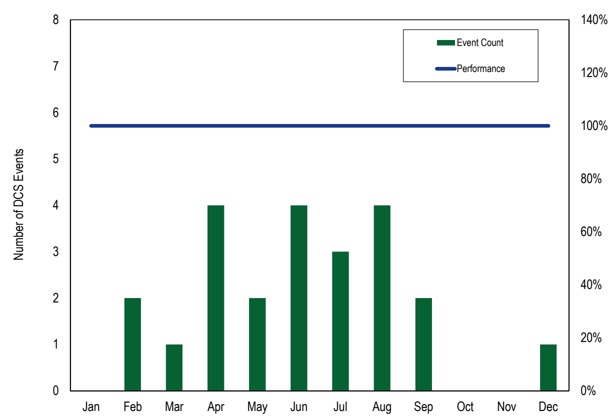
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 and BAAL standards requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[4] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 1,000 MW[5]. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 23 DCS events during calendar year 2011 and successfully recovered from all of them. Recovery times ranged from five minutes to 27 minutes. Figure F-2 illustrates the event count by month. All of the events resulted in low ACE. The solution in all 23 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2011



Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. The market clearing software (SPREGO) creates a regulation supply curve as part of a two product, and two constraint optimized solution. The price of the

4 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB).

5 The *2010 State of the Market Report for PJM*, Volume II, Appendix F, p.659 "Ancillary Service Markets" indicated that the previous DCS threshold, 800 MW, applied for all of 2010. In fact, the threshold was changed to 1,000 MW on July 1 of 2010.

most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for two products (regulation and synchronized reserve) with two constraints (energy and operating reserves) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.
- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation and did so for the first time in November of 2011. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers that are not set to "Unavailable" for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.
- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

  Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

  For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule.[6] Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices

6 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" for a full discussion of opportunity costs.

are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.
- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

Congestion and Marginal Losses

Locational Marginal Price (LMP) is the incremental price of energy at a bus. LMP at any bus is made up of three basic components: the system marginal price (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring incremental considerations of losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the generation of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[1] Congestion results from physical limitations of elements of the transmission system to move power from point to point. Congestion costs reflect the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

LMP Components Real-Time and Day-Ahead

Table G-1 details the components of real-time LMP year over year basis from 2008 through 2011. Table G-2 compares 2010 real-time LMP components by zone to 2011 real-time LMP components by zone. Table G-3 compares 2010 real-time LMP components by hub to 2011 LMP components by hub. Table G-4 details the components of day-ahead LMP year over year basis from 2008 through 2011. Table G-5 compares 2010 day-ahead LMP components by zone to 2011 day-ahead LMP components by zone.

Table G-1 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011	$42.84	$42.77	$0.05	$0.02

Congestion Costs

Zonal Congestion Costs

Day-ahead and balancing congestion costs within zones for calendar years 2011 and 2010 are presented in Table G-6 and Table G-7.[3] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear congestion costs. Load congestion payments, when positive, measure the congestion cost to load in an area. Load congestion payments, when negative, measure the congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the congestion credit to generation in an area. Generation congestion credits, when negative, measure the congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints For example, congestion across the AP South interface

1 For additional information, see the *MMU Technical Reference for PJM Markets*, at, "Marginal Losses."

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

3 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012 the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by $0.72 Million, a discrepancy of 0.07 percent (.0007).

Table G-2 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.67	$44.72	$3.64	$2.31	$47.56	$42.77	$2.80	$1.99
AEP	$38.36	$44.72	($4.83)	($1.53)	$39.04	$42.77	($2.41)	($1.32)
AP	$44.62	$44.72	$0.12	($0.22)	$42.91	$42.77	$0.23	($0.09)
ATSI	NA	NA	NA	NA	$39.24	$41.20	($1.79)	($0.17)
BGE	$53.63	$44.72	$6.68	$2.23	$49.11	$42.77	$4.40	$1.93
ComEd	$33.35	$44.72	($8.58)	($2.80)	$33.30	$42.77	($6.92)	($2.55)
DAY	$38.11	$44.72	($5.69)	($0.91)	$39.22	$42.77	($2.81)	($0.74)
DLCO	$37.14	$44.72	($5.94)	($1.64)	$38.98	$42.77	($2.48)	($1.31)
Dominion	$51.04	$44.72	$3.82	$2.51	$47.33	$42.77	$2.32	$2.25
DPL	$50.94	$44.72	$5.35	$0.87	$46.38	$42.77	$3.02	$0.60
JCPL	$49.88	$44.72	$2.92	$2.23	$47.65	$42.77	$2.84	$2.04
Met-Ed	$49.14	$44.72	$3.47	$0.95	$45.82	$42.77	$2.34	$0.72
PECO	$49.11	$44.72	$2.84	$1.55	$46.56	$42.77	$2.37	$1.42
PENELEC	$43.07	$44.72	($1.42)	($0.24)	$42.95	$42.77	($0.19)	$0.37
Pepco	$47.75	$44.72	$2.34	$0.69	$45.84	$42.77	$2.42	$0.65
PPL	$50.97	$44.72	$3.99	$2.26	$48.17	$42.77	$3.30	$2.10
PSEG	$52.85	$44.72	$6.72	$1.41	$47.34	$42.77	$3.44	$1.13
RECO	$49.18	$44.72	$2.50	$1.95	$44.28	$42.77	($0.37)	$1.88

Table G-3 Hub real-time, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.56	$44.72	($6.15)	($3.01)	$37.08	$42.77	($3.00)	($2.69)
AEP-DAY Hub	$37.57	$44.72	($5.42)	($1.73)	$38.55	$42.77	($2.69)	($1.52)
ATSI Gen Hub	NA	NA	NA	NA	$38.87	$41.19	($1.77)	($0.55)
Chicago Gen Hub	$32.23	$44.72	($9.09)	($3.40)	$32.25	$42.77	($7.41)	($3.10)
Chicago Hub	$33.54	$44.72	($8.40)	($2.78)	$33.48	$42.77	($6.78)	($2.51)
Dominion Hub	$49.43	$44.72	$4.30	$0.40	$45.84	$42.77	$2.87	$0.20
Eastern Hub	$50.98	$44.72	$3.59	$2.66	$47.71	$42.77	$2.48	$2.47
N Illinois Hub	$33.08	$44.72	($8.61)	($3.02)	$33.07	$42.77	($6.95)	($2.76)
New Jersey Hub	$50.46	$44.72	$3.52	$2.21	$47.88	$42.77	$3.08	$2.03
Ohio Hub	$37.64	$44.72	($5.41)	($1.67)	$38.58	$42.77	($2.73)	($1.45)
West Interface Hub	$40.50	$44.72	($2.76)	($1.46)	$40.57	$42.77	($1.21)	($0.99)
Western Hub	$45.93	$44.72	$1.52	($0.31)	$43.56	$42.77	$0.88	($0.09)

Table G-4 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2008 through 2011

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$44.57	$44.61	$0.03	($0.06)
2011	$42.52	$42.72	($0.07)	($0.13)

Table G-5 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2010 and 2011

	2010				2011			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.44	$44.61	$2.96	$2.87	$47.86	$42.72	$2.84	$2.30
AEP	$38.30	$44.61	($4.05)	($2.26)	$39.32	$42.72	($1.93)	($1.47)
AP	$44.42	$44.61	$0.06	($0.25)	$42.96	$42.72	$0.29	($0.05)
ATSI	NA	NA	NA	NA	$39.34	$41.59	($1.37)	($0.88)
BGE	$53.24	$44.61	$5.75	$2.88	$48.66	$42.72	$3.69	$2.25
ComEd	$33.37	$44.61	($7.38)	($3.86)	$33.46	$42.72	($6.15)	($3.12)
DAY	$37.97	$44.61	($4.74)	($1.89)	$39.29	$42.72	($2.60)	($0.83)
DLCO	$37.84	$44.61	($4.75)	($2.02)	$38.89	$42.72	($2.52)	($1.31)
Dominion	$50.80	$44.61	$3.17	$3.02	$47.93	$42.72	$2.61	$2.59
DPL	$51.16	$44.61	$5.10	$1.45	$46.00	$42.72	$2.61	$0.66
JCPL	$50.21	$44.61	$2.59	$3.01	$47.59	$42.72	$2.48	$2.38
Met-Ed	$48.98	$44.61	$3.13	$1.24	$45.82	$42.72	$2.37	$0.72
PECO	$49.58	$44.61	$2.69	$2.28	$47.21	$42.72	$2.71	$1.78
PENELEC	$43.94	$44.61	($0.68)	$0.01	$42.79	$42.72	($0.17)	$0.24
Pepco	$47.67	$44.61	$2.20	$0.86	$45.68	$42.72	$2.37	$0.59
PPL	$50.89	$44.61	$3.04	$3.24	$48.32	$42.72	$3.06	$2.53
PSEG	$52.94	$44.61	$6.16	$2.18	$47.58	$42.72	$3.35	$1.51
RECO	$49.68	$44.61	$2.19	$2.88	$45.80	$42.72	$1.13	$1.95

means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion, but the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The ComEd Control Zone, AEP Control Zone and the AP Control Zone are examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $239.0 million, of any control zone in 2011. The positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This somewhat counter intuitive result is the result of congestion accounting conventions.

The AEP Control Zone had the second highest congestion charges, $195.1 million of any control zone in 2011. The positive congestion costs in the AEP Control Zone were the result of negative load congestion payments offset by a bigger negative generation congestion credits. The AP Control Zone had the third highest congestion charges, $143.9 million, of any control zone in 2011. The positive congestion costs in the AP Control Zone were the result of relatively low positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for AP rather than offsetting the positive load congestion payments.

Table G-6 Congestion cost summary (By control zone): Calendar year 2011

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$45.4	$15.7	$0.7	$30.5	($0.4)	$0.2	($1.0)	($1.6)	$28.9
AEP	($377.8)	($606.7)	$23.0	$251.8	$9.4	$37.2	($28.9)	($56.7)	$195.1
AP	$6.9	($143.7)	($2.6)	$148.1	$5.7	$8.0	($1.8)	($4.1)	$143.9
ATSI	($73.8)	($78.5)	$1.6	$6.3	$2.1	$8.0	($3.3)	($9.2)	($2.9)
BGE	$233.4	$180.3	$8.0	$61.0	$2.8	$1.8	($11.5)	($10.5)	$50.5
ComEd	($1,064.7)	($1,323.5)	($4.2)	$254.6	$57.4	$46.2	($26.7)	($15.5)	$239.0
DAY	($61.3)	($70.1)	$1.3	$10.1	$3.4	$6.1	($4.4)	($7.1)	$3.0
DLCO	($43.2)	($67.9)	$0.0	$24.7	($3.0)	$0.7	($0.7)	($4.4)	$20.4
DPL	$71.3	$28.6	$1.3	$44.0	$0.5	$3.9	($1.8)	($5.2)	$38.8
Dominion	$537.7	$375.1	$23.1	$185.7	($4.8)	$4.5	($37.7)	($47.0)	$138.7
External	($56.3)	($42.5)	($6.5)	($20.3)	($10.4)	($19.1)	($23.8)	($15.1)	($35.4)
JCPL	$78.8	$35.4	$1.0	$44.4	$3.9	$1.3	($1.5)	$1.1	$45.5
Met-Ed	$46.0	$48.1	$0.5	($1.7)	$1.7	$0.8	($0.7)	$0.2	($1.5)
PECO	$178.0	$163.2	$0.9	$15.7	($0.9)	$5.2	($1.1)	($7.2)	$8.5
PENELEC	($45.9)	($108.1)	$0.7	$62.9	$4.2	$7.2	($1.2)	($4.2)	$58.7
PPL	$137.2	$142.1	$5.0	$0.0	$6.7	$2.9	($3.3)	$0.5	$0.5
PSEG	$191.8	$154.3	$7.6	$45.1	$1.3	$17.7	($33.9)	($50.4)	($5.3)
Pepco	$230.7	$156.5	$5.4	$79.6	($3.6)	($1.8)	($6.6)	($8.4)	$71.1
RECO	$2.3	($0.1)	$0.1	$2.6	$0.0	$1.0	($0.2)	($1.1)	$1.5
Total	$36.3	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0

Table G-7 Congestion cost summary (By control zone): Calendar year 2010

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$43.6	$17.8	$0.3	$26.0	$0.4	($1.4)	($0.1)	$1.7	$27.7
AEP	($750.5)	($965.2)	$11.3	$225.9	($12.5)	$40.3	($19.0)	($71.7)	$154.2
AP	($5.9)	($313.4)	$0.8	$308.4	$11.7	$32.9	($5.2)	($26.4)	$282.0
BGE	$358.8	$285.7	$9.3	$82.4	$14.1	($6.0)	($11.4)	$8.7	$91.1
ComEd	($1,264.9)	($1,576.1)	($5.5)	$305.8	($15.0)	$16.2	($11.9)	($43.1)	$262.7
DAY	($108.9)	($120.2)	$5.6	$16.9	$3.4	$3.8	($6.9)	($7.3)	$9.6
DLCO	($151.5)	($196.0)	($0.7)	$43.7	($11.5)	$1.6	$0.2	($12.9)	$30.9
DPL	$82.2	$33.1	$1.3	$50.4	($0.8)	$0.9	($1.6)	($3.3)	$47.1
Dominion	$1,118.1	$825.6	$15.9	$308.4	$1.8	$6.7	($18.9)	($23.9)	$284.5
External	($196.9)	($211.5)	$17.4	$32.0	$0.4	($21.8)	($69.5)	($47.3)	($15.2)
JCPL	$84.3	$34.8	$0.5	$50.1	$0.2	($1.3)	($0.7)	$0.8	$50.9
Met-Ed	$62.9	$53.9	$1.3	$10.4	($0.9)	$0.1	($1.6)	($2.5)	$7.8
PECO	$275.7	$285.2	$0.3	($9.2)	($3.5)	$1.7	($0.9)	($6.0)	($15.2)
PENELEC	($124.0)	($221.9)	$1.0	$98.9	$17.1	$8.6	($0.7)	$7.8	$106.7
PPL	$119.0	$133.1	$3.6	($10.5)	$12.8	$9.5	($0.5)	$2.8	($7.7)
PSEG	$204.6	$175.3	$28.3	$57.6	($8.2)	$21.2	($23.6)	($53.0)	$4.6
Pepco	$501.2	$394.8	$6.1	$112.5	($10.9)	($3.0)	($6.9)	($14.9)	$97.7
RECO	$3.5	$0.2	$0.1	$3.4	$1.0	($0.0)	($0.2)	$0.9	$4.3
Total	$251.4	($1,364.8)	$96.9	$1,713.1	($0.2)	$110.1	($179.3)	($289.6)	$1,423.6

Details of Regional and Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with 6 control zones (the AP, ATSI, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table G-8 through Table G-42 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2011 and 2010. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. The tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. In 2011, the RECO control zone did not have any internal constraints, thus the RECO table shows only the top 15 constraints.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table G-8 AECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
				Load	Generation			Load	Generation			Grand	Day	Real
No.	Constraint	Type	Location	Payments	Credits	Explicit	Total	Payments	Credits	Explicit	Total	Total	Ahead	Time
1	West	Interface	500	$9.7	$3.7	$0.1	$6.1	$0.0	($0.0)	($0.0)	$0.0	$6.1	1,734	40
2	5004/5005 Interface	Interface	500	$7.4	$3.3	$0.0	$4.2	$0.2	($0.4)	($0.1)	$0.5	$4.6	1,810	940
3	Sherman Avenue	Transformer	AECO	$4.6	$0.3	$0.1	$4.3	($0.2)	($0.1)	($0.0)	($0.1)	$4.2	1,196	60
4	East	Interface	500	$3.8	$1.4	$0.0	$2.4	($0.0)	($0.0)	($0.0)	($0.0)	$2.3	1,044	44
5	Wylie Ridge	Transformer	AP	$2.8	$1.1	$0.0	$1.7	$0.1	($0.1)	($0.0)	$0.2	$2.0	3,836	760
6	Graceton - Raphael Road	Line	BGE	($2.0)	($0.6)	($0.0)	($1.4)	($0.0)	$0.1	$0.0	($0.1)	($1.5)	2,314	830
7	Crete - St Johns Tap	Flowgate	MISO	$1.6	$0.4	$0.0	$1.1	$0.1	($0.0)	($0.0)	$0.1	$1.2	6,708	2,230
8	Shieldalloy - Vineland	Line	AECO	$3.9	$0.8	$0.2	$3.2	($1.4)	$0.5	($0.3)	($2.2)	$1.0	1,496	468
9	AP South	Interface	500	$1.5	$0.6	$0.1	$0.9	($0.0)	($0.1)	($0.1)	$0.0	$1.0	8,222	2,026
10	Dickerson - Quince Orchard	Line	Pepco	$1.4	$0.7	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.8	284	152
11	South Mahwah - Waldwick	Line	PSEG	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	$0.0	$0.7	10,538	988
12	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	3,092	658
13	Orchard - Orchard Tap	Line	AECO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	70	0
14	Plymouth Meeting - Whitpain	Line	PECO	$0.8	$0.4	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	412	144
15	Burnham - Munster	Flowgate	MISO	$0.6	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,304	0
17	Orchard	Transformer	AECO	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0
19	Corson	Transformer	AECO	$0.1	($0.0)	$0.0	$0.1	$0.4	$0.1	($0.0)	$0.2	$0.3	62	52
26	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.2	($0.0)	($0.4)	($0.3)	188	88
44	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	66
58	Carnegie - Tidd	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,704	0

Table G-9 AECO Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
				Load	Generation			Load	Generation			Grand	Day	Real
No.	Constraint	Type	Location	Payments	Credits	Explicit	Total	Payments	Credits	Explicit	Total	Total	Ahead	Time
1	5004/5005 Interface	Interface	500	$8.2	$3.7	$0.0	$4.5	$0.6	($0.7)	($0.0)	$1.2	$5.8	2,758	1,142
2	England - Middletap	Line	AECO	$4.0	$0.7	$0.0	$3.3	($0.4)	($0.4)	($0.0)	($0.0)	$3.2	672	138
3	West	Interface	500	$3.7	$1.8	$0.0	$1.9	$0.1	$0.0	$0.0	$0.1	$2.0	322	116
4	Monroe	Transformer	AECO	$1.7	$0.2	$0.0	$1.5	$0.1	($0.2)	($0.0)	$0.2	$1.8	464	96
5	Brandon Shores - Riverside	Line	BGE	$2.3	$1.1	$0.0	$1.3	$0.0	($0.2)	($0.0)	$0.2	$1.5	686	324
6	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	($1.4)	$0.1	($0.1)	($1.6)	($1.4)	162	36
7	Graceton - Raphael Road	Line	BGE	($1.5)	($0.5)	($0.0)	($0.9)	($0.1)	$0.1	$0.0	($0.2)	($1.2)	682	468
8	AP South	Interface	500	$1.9	$0.9	$0.0	$1.0	$0.1	($0.0)	($0.0)	$0.1	$1.1	7,080	2,502
9	Shieldalloy - Vineland	Line	AECO	$3.2	$0.9	$0.1	$2.3	($1.2)	$0.1	($0.0)	($1.3)	$1.1	458	326
10	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.9	$0.2	($0.0)	($0.0)	$0.2	$1.0	5,584	1,700
11	Tiltonsville - Windsor	Line	AP	$1.1	$0.4	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.2	$0.9	5,204	940
12	Branchburg - Readington	Line	PSEG	($1.3)	($0.5)	($0.0)	($0.8)	($0.1)	$0.0	$0.0	($0.1)	($0.8)	2,434	368
13	Bedington - Black Oak	Interface	500	$1.3	$0.6	$0.0	$0.8	$0.0	$0.0	($0.0)	$0.0	$0.8	3,704	222
14	Cloverdale - Lexington	Line	500	$0.8	$0.3	$0.0	$0.5	$0.2	$0.0	($0.0)	$0.2	$0.7	2,138	1,356
15	Brunner Island - Yorkana	Line	Met-Ed	($0.6)	($0.3)	($0.0)	($0.4)	($0.1)	$0.1	$0.0	($0.2)	($0.6)	474	360
24	Corson - Court	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	14	30
36	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.2	$0.2	0	32
48	Sherman Avenue	Transformer	AECO	$0.2	($0.0)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.1	62	38
78	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	0	34
88	Lewis - Motts - Cedar	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	50	0

BGE Control Zone

Table G-10 BGE Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$29.1	$21.1	$0.5	$8.5	$0.0	($0.1)	($0.0)	$0.1	$8.6	1,734	40
2	AP South	Interface	500	$58.6	$53.5	$1.7	$6.9	$1.4	($0.5)	($1.7)	$0.3	$7.1	8,222	2,026
3	Dickerson - Quince Orchard	Line	Pepco	$15.2	$11.0	$0.1	$4.3	$0.6	$0.4	($0.4)	($0.1)	$4.2	284	152
4	Wagner	Transformer	BGE	$4.2	$0.8	$0.1	$3.5	($0.1)	($0.6)	($0.3)	$0.2	$3.7	402	52
5	Riverside	Other	BGE	$0.5	$0.1	$0.0	$0.4	($0.1)	$2.8	($0.9)	($3.7)	($3.3)	40	262
6	Graceton - Raphael Road	Line	BGE	$14.6	$11.0	$0.6	$4.2	($0.1)	$0.4	($0.7)	($1.2)	$3.1	2,314	830
7	Pumphrey	Transformer	Pepco	$4.9	$2.1	$0.2	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	486	0
8	5004/5005 Interface	Interface	500	$10.9	$8.4	$0.1	$2.6	$0.1	($0.2)	($0.1)	$0.2	$2.8	1,810	940
9	Riverside - Riverside	Other	BGE	$2.3	($0.1)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1,098	0
10	Wylie Ridge	Transformer	AP	$12.0	$10.3	$0.3	$2.0	$0.3	($0.1)	($0.2)	$0.2	$2.2	3,836	760
11	Conastone - Graceton	Line	BGE	$5.3	$3.6	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	236	0
12	Crete - St Johns Tap	Flowgate	MISO	$7.9	$6.7	$0.2	$1.4	$0.3	$0.1	($0.2)	$0.0	$1.5	6,708	2,230
13	High Ridge - Howard	Line	BGE	$3.2	$1.0	$0.2	$2.3	($0.7)	($0.2)	($0.4)	($0.9)	$1.4	204	92
14	Glenarm - Windy Edge	Line	BGE	$5.3	$3.6	$0.3	$2.0	($0.0)	$0.3	($0.2)	($0.6)	$1.4	1,366	316
15	Brandon Shores - Riverside	Line	BGE	$0.9	($0.4)	$0.1	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	276	18
18	Erdman - Monument St.	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	14	0
20	Howard - Pumphrey	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.9)	($0.8)	($0.6)	($0.6)	0	120
28	Northwest	Other	BGE	$0.7	$0.5	$0.0	$0.3	($0.1)	$0.3	($0.2)	($0.6)	($0.4)	90	206
30	Chesaco Park - Gray Manor	Line	BGE	$0.3	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	104	0
31	East Point - Riverside	Line	BGE	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	72	0

Table G-11 BGE Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Brandon Shores - Riverside	Line	BGE	$17.0	($8.8)	$0.2	$26.0	($2.1)	$0.2	($0.3)	($2.5)	$23.5	686	324
2	AP South	Interface	500	$45.9	$35.1	$1.9	$12.6	$3.5	($1.4)	($1.6)	$3.4	$16.0	7,080	222
3	Doubs	Transformer	AP	$11.9	$7.1	$0.3	$5.1	$1.0	($1.2)	($0.5)	$1.8	$6.9	2,492	896
4	Bedington - Black Oak	Interface	500	$17.9	$13.2	$0.6	$5.3	$0.5	($0.3)	($0.4)	$0.4	$5.7	3,704	222
5	5004/5005 Interface	Interface	500	$7.3	$3.6	$0.3	$4.0	$0.5	($0.2)	($0.3)	$0.4	$4.5	2,758	1,142
6	West	Interface	500	$6.3	$3.1	$0.0	$3.2	$0.2	($0.0)	($0.0)	$0.2	$3.4	322	116
7	Graceton - Raphael Road	Line	BGE	$6.6	$4.3	$0.4	$2.8	$0.2	($0.5)	($0.5)	$0.1	$2.9	682	468
8	Mount Storm - Pruntytown	Line	500	$4.1	$3.5	$0.2	$0.8	$1.3	($0.6)	($0.6)	$1.4	$2.2	1,142	1,148
9	Brunner Island - Yorkana	Line	Met-Ed	$3.5	$2.0	$0.2	$1.7	$0.2	($0.0)	($0.2)	($0.1)	$1.6	474	360
10	Millville - Sleepy Hollow	Line	Dominion	$4.3	$3.3	$0.4	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	802	0
11	Cloverdale - Lexington	Line	500	$4.7	$4.4	$0.2	$0.5	$0.9	($0.3)	($0.3)	$0.9	$1.4	2,138	1,356
12	Tiltonsville - Windsor	Line	AP	$2.9	$2.0	$0.1	$1.0	$0.2	($0.1)	($0.1)	$0.2	$1.2	5,204	940
13	East Frankfort - Crete	Line	ComEd	$3.2	$2.5	$0.1	$0.8	$0.3	($0.1)	($0.0)	$0.4	$1.2	5,584	1,700
14	Pumphrey	Transformer	Pepco	$1.1	$0.3	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	112	0
15	Five Forks - Rock Ridge	Line	Dominion	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.5	($0.1)	($0.9)	($0.9)	0	76
27	Fullerton - Windyedge	Line	BGE	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	46	0
28	Graceton - Safe Harbor	Line	BGE	$0.9	$0.6	$0.1	$0.5	$0.2	$0.1	($0.2)	($0.0)	$0.4	208	140
30	Glenarm - Windy Edge	Line	BGE	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	148	78
34	Green Street - Westport	Line	BGE	$0.3	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	290	0
46	Five Forks - Rock Ridge	Line	BGE	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	78	0

DPL Control Zone

Table G-12 DPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$14.0	$5.0	$0.1	$9.1	$0.3	$0.8	($0.3)	($0.8)	$8.3	1,810	940
2	West	Interface	500	$16.2	$8.8	$0.2	$7.6	$0.0	$0.0	($0.0)	$0.0	$7.6	1,734	40
3	Wylie Ridge	Transformer	AP	$5.7	$1.6	$0.1	$4.1	$0.1	$0.2	($0.0)	($0.1)	$4.0	3,836	760
4	East	Interface	500	$7.0	$3.1	($0.0)	$3.8	($0.0)	$0.1	($0.0)	($0.1)	$3.8	1,044	44
5	AP South	Interface	500	$4.1	$1.5	$0.2	$2.9	$0.0	$0.3	($0.3)	($0.6)	$2.3	8,222	2,026
6	Crete - St Johns Tap	Flowgate	MISO	$3.0	$0.8	$0.0	$2.3	$0.1	$0.3	($0.0)	($0.2)	$2.0	6,708	2,230
7	Graceton - Raphael Road	Line	BGE	($3.9)	($1.4)	($0.3)	($2.8)	($0.1)	($0.6)	$0.2	$0.8	($2.0)	2,314	830
8	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	980	0
9	Plymouth Meeting - Whitpain	Line	PECO	$2.3	$1.0	$0.0	$1.3	$0.1	$0.1	($0.1)	($0.0)	$1.3	412	144
10	Longwood - Wye Mills	Line	DPL	$1.5	$0.4	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	1,768	6
11	Burnham - Munster	Flowgate	MISO	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	2,304	0
12	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	3,092	658
13	Glenarm - Windy Edge	Line	BGE	($1.1)	($0.4)	($0.0)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	($0.7)	1,366	316
14	Bedington - Black Oak	Interface	500	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	1,358	14
15	Dickerson - Quince Orchard	Line	Pepco	$2.5	$1.6	$0.0	$1.0	$0.1	$0.4	($0.0)	($0.4)	$0.6	284	152
22	Hallwood - Oak Hall	Line	DPL	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	362	0
24	Mardela - Vienna	Line	DPL	$0.4	$0.1	$0.0	$0.4	($0.2)	$0.4	($0.1)	($0.8)	($0.4)	310	52
29	Easton - Trappe	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	248	0
47	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,220	0
53	Oak Hall	Transformer	DPL	$0.2	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	10	0

Table G-13 DPL Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$13.3	$5.7	$0.1	$7.7	$0.5	($0.0)	($0.2)	$0.3	$8.1	2,758	1,142
2	AP South	Interface	500	$5.0	$2.2	$0.1	$2.9	$0.2	$0.0	($0.0)	$0.1	$3.0	7,080	2,502
3	Oak Hall	Transformer	DPL	$2.7	$0.5	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,218	0
4	West	Interface	500	$5.3	$3.4	$0.0	$1.9	$0.1	$0.1	($0.0)	$0.0	$1.9	322	116
5	East Frankfort - Crete	Line	ComEd	$2.1	$0.3	$0.0	$1.8	$0.0	$0.0	($0.0)	$0.0	$1.8	5,584	1,700
6	New Church - Piney Grove	Line	DPL	$1.9	$0.4	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	600	0
7	Bedington - Black Oak	Interface	500	$2.7	$1.2	$0.0	$1.6	$0.0	$0.0	($0.0)	($0.1)	$1.5	3,704	222
8	Brandon Shores - Riverside	Line	BGE	$3.4	$2.0	$0.0	$1.5	$0.1	($0.0)	($0.0)	$0.1	$1.5	686	324
9	Graceton - Raphael Road	Line	BGE	($2.7)	($1.1)	($0.0)	($1.6)	($0.0)	($0.2)	$0.1	$0.2	($1.3)	682	468
10	Longwood - Wye Mills	Line	DPL	$1.6	$0.3	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	520	0
11	Middletown - Mt Pleasant	Line	DPL	$1.7	$0.4	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	326	0
12	Cloverdale - Lexington	Line	500	$1.4	$0.3	$0.0	$1.1	$0.2	$0.0	($0.1)	$0.1	$1.2	2,138	1,356
13	Tiltonsville - Windsor	Line	AP	$1.8	$0.8	$0.1	$1.1	$0.0	($0.0)	($0.1)	($0.0)	$1.1	5,204	940
14	Kenney - Stockton	Line	DPL	$1.0	$0.3	$0.0	$0.7	($1.6)	($0.0)	($0.1)	($1.7)	($1.0)	192	244
15	Branchburg - Readington	Line	PSEG	($1.9)	($0.9)	($0.1)	($1.0)	($0.0)	($0.0)	$0.0	$0.1	($1.0)	2,434	368
17	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	16
20	Easton - Trappe	Line	DPL	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	234	0
23	Dupont Seaford - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.4	($0.0)	($0.7)	($0.7)	0	30
24	Keeney At5n	Transformer	DPL	$0.0	($0.0)	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	52	26
25	Cecil - Colora	Line	DPL	$1.3	$0.4	$0.1	$1.0	($0.1)	$0.0	($0.1)	($0.3)	$0.7	258	78

JCPL Control Zone

Table G-14 JCPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$19.0	$8.6	$0.1	$10.5	$0.9	$0.2	($0.1)	$0.6	$11.0	1,810	940
2	West	Interface	500	$19.8	$11.4	$0.1	$8.6	($0.0)	($0.0)	($0.0)	($0.0)	$8.5	1,734	40
3	Redoak - Sayreville	Line	JCPL	($1.3)	($5.3)	($0.1)	$3.9	$0.0	$0.1	$0.0	($0.1)	$3.8	3,504	22
4	South Mahwah - Waldwick	Line	PSEG	$6.7	$3.0	$0.3	$4.1	($0.1)	($0.0)	($0.3)	($0.4)	$3.7	10,538	988
5	Wylie Ridge	Transformer	AP	$6.5	$3.0	$0.0	$3.5	$0.1	$0.1	($0.0)	($0.0)	$3.5	3,836	760
6	East	Interface	500	$6.7	$3.7	$0.0	$3.0	($0.1)	$0.0	($0.0)	($0.1)	$2.9	1,044	44
7	Bridgewater - Middlesex	Line	PSEG	$4.6	$1.8	$0.2	$3.0	($0.2)	$0.2	($0.5)	($0.9)	$2.1	1,108	126
8	Cedar Grove - Roseland	Line	PSEG	($3.1)	($1.2)	($0.1)	($2.1)	$0.0	$0.0	$0.0	$0.0	($2.0)	1,812	74
9	Crete - St Johns Tap	Flowgate	MISO	$3.6	$1.8	$0.0	$1.8	$0.1	$0.1	($0.0)	($0.0)	$1.8	6,708	2,230
10	Dickerson - Quince Orchard	Line	Pepco	$2.6	$1.6	$0.0	$1.0	$0.4	$0.1	($0.0)	$0.3	$1.3	284	152
11	Graceton - Raphael Road	Line	BGE	($4.1)	($2.7)	($0.1)	($1.5)	$0.4	$0.1	$0.1	$0.4	($1.2)	2,314	830
12	East Windsor - Smithburg	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.9	($0.0)	$0.0	$0.9	$0.9	0	18
13	Susquehanna	Transformer	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
14	East Frankfort - Crete	Line	ComEd	$1.4	$0.8	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	3,092	658
15	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	168	2
42	Flanders - W. Wharton	Line	JCPL	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	550	0
48	Kilmer - Sayreville	Line	JCPL	$0.3	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	186	0
62	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	28
166	Lakewood - Larrabee	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
179	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table G-15 JCPL Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$18.0	$8.0	$0.0	$10.0	$1.0	($0.2)	($0.1)	$1.1	$11.1	2,758	1,142
2	Branchburg - Readington	Line	PSEG	$6.8	$0.4	$0.1	$6.5	($0.5)	($0.3)	$0.1	($0.2)	$6.3	2,434	368
3	West	Interface	500	$7.5	$4.0	$0.0	$3.6	$0.0	($0.1)	($0.0)	$0.2	$3.7	322	116
4	Redoak - Sayreville	Line	JCPL	($2.0)	($5.8)	$0.0	$3.8	$0.1	$0.7	$0.0	($0.6)	$3.2	1,700	114
5	Athenia - Saddlebrook	Line	PSEG	($3.2)	($1.0)	($0.0)	($2.2)	($0.2)	$0.1	$0.0	($0.2)	($2.4)	5,918	662
6	Brandon Shores - Riverside	Line	BGE	$4.4	$2.3	$0.0	$2.1	$0.1	($0.1)	($0.0)	$0.1	$2.3	686	324
7	East Frankfort - Crete	Line	ComEd	$2.8	$1.4	($0.0)	$1.4	$0.0	($0.1)	$0.0	$0.1	$1.5	5,584	1,700
8	Tiltonsville - Windsor	Line	AP	$2.6	$1.4	$0.0	$1.2	($0.0)	($0.1)	($0.0)	$0.0	$1.3	5,204	940
9	Graceton - Raphael Road	Line	BGE	($3.2)	($1.8)	($0.0)	($1.4)	$0.3	$0.1	$0.0	$0.2	($1.2)	682	468
10	Cloverdale - Lexington	Line	500	$1.6	$0.7	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$1.0	2,138	1,356
11	Atlantic - Larrabee	Line	JCPL	$0.9	$0.1	$0.0	$0.9	$0.0	($0.1)	($0.0)	$0.1	$0.9	246	24
12	Bedington - Black Oak	Interface	500	$1.5	$0.8	$0.1	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	3,704	222
13	Brunner Island - Yorkana	Line	Met-Ed	($2.0)	($1.2)	($0.0)	($0.9)	$0.3	$0.1	$0.0	$0.2	($0.7)	474	360
14	Wylie Ridge	Transformer	AP	$1.2	$0.6	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.6	1,010	752
15	Millville - Sleepy Hollow	Line	Dominion	$1.6	$0.9	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	802	0
30	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	8
35	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	122	0
41	Kilmer - Sayreville	Line	JCPL	$0.5	$0.3	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	234	0
203	Montville - Roseland	Line	JCPL	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	10
237	Greystone - West Wharton	Line	JCPL	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Met-Ed Control Zone

Table G-16 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$10.9	$15.5	$0.1	($4.6)	$0.0	$0.0	($0.0)	($0.0)	($4.6)	1,734	40
2	Cly - Collins	Line	Met-Ed	$1.9	($1.3)	$0.1	$3.3	($0.5)	$0.4	($0.0)	($0.9)	$2.3	710	324
3	Wylie Ridge	Transformer	AP	$4.4	$6.3	$0.1	($1.8)	$0.1	($0.0)	($0.0)	$0.1	($1.7)	3,836	760
4	Hunterstown	Transformer	Met-Ed	$1.6	$0.0	$0.0	$1.5	$0.0	$0.0	($0.0)	$0.0	$1.5	164	18
5	Middletown Jct - TMI	Line	Met-Ed	$0.4	($0.7)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	62	0
6	Crete - St Johns Tap	Flowgate	MISO	$2.4	$3.4	($0.0)	($1.0)	$0.1	($0.0)	($0.0)	$0.1	($0.9)	6,708	2,230
7	Graceton - Raphael Road	Line	BGE	($3.3)	($4.6)	($0.2)	$1.1	($0.1)	$0.2	$0.1	($0.2)	$0.9	2,314	830
8	East	Interface	500	$0.4	($0.2)	($0.1)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,044	44
9	Carlisle Pike - Roxbury	Line	PENELEC	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	268	8
10	Dickerson - Quince Orchard	Line	Pepco	$1.3	$1.9	$0.0	($0.5)	$0.2	$0.1	($0.0)	$0.1	($0.5)	284	152
11	East Frankfort - Crete	Line	ComEd	$0.9	$1.3	$0.0	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	3,092	658
12	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.4)	($0.4)	0	30
13	Burnham - Munster	Flowgate	MISO	$1.0	$1.4	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
14	Conastone - Graceton	Line	BGE	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	236	0
15	Glenarm - Windy Edge	Line	BGE	($1.1)	($1.4)	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.3	1,366	316
22	Glendon - Hosensack	Line	Met-Ed	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	140	2
29	Hunterstown - Lincoln	Line	Met-Ed	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	220	16
31	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	74	0
39	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
71	Manor - Safe Harbor	Line	Met-Ed	($0.1)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	14	6

Table G-17 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Brunner Island - Yorkana	Line	Met-Ed	$1.9	($4.1)	$0.1	$6.1	$0.0	$0.2	($0.0)	($0.2)	$6.0	474	360
2	Hunterstown	Transformer	Met-Ed	$4.0	($0.7)	$0.1	$4.7	$0.0	$0.0	($0.0)	($0.0)	$4.7	622	52
3	West	Interface	500	$4.2	$5.4	$0.0	($1.1)	$0.0	($0.1)	($0.0)	$0.1	($1.1)	322	116
4	Doubs	Transformer	AP	$3.2	$2.1	$0.1	$1.2	($0.0)	($0.1)	($0.3)	($0.2)	$0.9	2,492	896
5	Graceton - Raphael Road	Line	BGE	($2.1)	($3.1)	($0.0)	$1.0	$0.2	$0.3	$0.1	($0.0)	$0.9	682	468
6	AP South	Interface	500	$4.9	$4.0	$0.1	$1.0	($0.1)	($0.0)	($0.2)	($0.2)	$0.8	7,080	2,502
7	Jackson - TMI	Line	Met-Ed	$0.5	($0.6)	$0.1	$1.2	($0.1)	$0.3	($0.0)	($0.4)	$0.8	74	108
8	5004/5005 Interface	Interface	500	$10.7	$10.3	$0.0	$0.5	($0.3)	($0.7)	($0.1)	$0.2	$0.7	2,758	1,142
9	Middletown Jct	Transformer	Met-Ed	$0.6	($0.1)	$0.0	$0.7	($0.1)	$0.1	$0.0	($0.1)	$0.6	22	24
10	Collins - Middletown Jct	Line	Met-Ed	$0.3	($0.3)	$0.0	$0.6	($0.0)	$0.1	($0.0)	($0.1)	$0.5	376	78
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	380	24
12	Brandon Shores - Riverside	Line	BGE	$3.2	$3.8	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	686	324
13	Cloverdale - Lexington	Line	500	$1.3	$1.7	$0.0	($0.3)	$0.0	$0.1	($0.0)	($0.1)	($0.5)	2,138	1,356
14	Wylie Ridge	Transformer	AP	$0.8	$1.1	$0.0	($0.3)	($0.0)	$0.0	($0.0)	($0.1)	($0.4)	1,010	752
15	Tiltonsville - Windsor	Line	AP	$1.6	$2.0	$0.0	($0.4)	($0.1)	($0.1)	($0.1)	($0.0)	($0.4)	5,204	940
23	Jackson - North Hanover	Line	Met-Ed	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	26
46	Cly - Collins	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0
67	Yorkana A	Transformer	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	10
68	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.0)	62	78
75	Germantown - Straban	Line	Met-Ed	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	22	0

PECO Control Zone

Table G-18 PECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$38.1	$45.9	$0.1	($7.6)	($0.0)	($0.0)	($0.0)	$0.0	($7.6)	1,734	40
2	Plymouth Meeting - Whitpain	Line	PECO	$11.1	$3.2	$0.0	$7.9	($0.3)	($0.0)	($0.1)	($0.4)	$7.6	412	144
3	East	Interface	500	$14.2	$8.9	$0.1	$5.4	($0.1)	$0.1	($0.0)	($0.2)	$5.2	1,044	44
4	Cromby	Transformer	PECO	$6.4	$0.6	$0.0	$5.8	($0.7)	$0.4	($0.0)	($1.1)	$4.7	756	304
5	Bryn Mawr - Plymouth Meeting	Line	PECO	$6.5	$2.0	$0.0	$4.4	($0.1)	($0.1)	$0.0	$0.0	$4.5	568	8
6	Graceton - Raphael Road	Line	BGE	($9.8)	($13.9)	($0.1)	$3.9	$0.5	$0.1	$0.1	$0.6	$4.5	2,314	830
7	AP South	Interface	500	$7.6	$11.8	$0.1	($4.0)	($0.2)	$0.1	($0.1)	($0.4)	($4.4)	8,222	2,026
8	5004/5005 Interface	Interface	500	$36.1	$38.8	$0.2	($2.5)	($0.6)	$1.0	($0.1)	($1.8)	($4.3)	1,810	940
9	Wylie Ridge	Transformer	AP	$14.0	$16.8	$0.1	($2.7)	($0.1)	$0.0	($0.1)	($0.1)	($2.8)	3,836	760
10	Bradford - Planebrook	Line	PECO	$2.4	($0.1)	$0.0	$2.5	$0.1	$0.3	$0.0	($0.2)	$2.3	242	86
11	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.0	$0.2	($0.0)	($0.2)	($2.1)	6,708	2,230
12	Dickerson - Quince Orchard	Line	Pepco	$5.9	$7.5	$0.0	($1.5)	$0.2	$0.5	($0.0)	($0.3)	($1.8)	284	152
13	Bala - Plymouth Meeting	Line	PECO	$2.6	$0.8	($0.0)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	152	0
14	Conastone - Graceton	Line	BGE	($0.6)	($2.1)	($0.0)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	236	0
15	Chichester	Transformer	PECO	$1.5	$0.1	$0.0	$1.5	($0.0)	$0.0	($0.0)	($0.1)	$1.4	118	8
16	Limerick	Transformer	PECO	$2.1	$0.7	($0.0)	$1.4	($0.0)	$0.0	($0.0)	($0.0)	$1.4	60	10
26	Eddystone - Saville	Line	PECO	$0.6	($0.0)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.0)	$0.6	136	32
27	Emilie	Transformer	PECO	($0.2)	($0.8)	($0.0)	$0.7	$0.1	$0.3	$0.0	($0.2)	$0.5	630	306
32	Eddington - Holmesburg	Line	PECO	($0.0)	($0.4)	($0.0)	$0.4	($0.1)	$0.7	($0.0)	($0.8)	($0.4)	482	356
35	Blue Grass - Byberry	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	116	0

Table G-19 PECO Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$10.0	$16.5	$0.0	($6.5)	($0.5)	$1.4	($0.1)	($2.0)	($8.5)	2,758	1,142
2	Eddystone - Island Road	Line	PECO	$3.8	($4.4)	($0.0)	$8.1	($0.0)	$0.0	$0.0	($0.0)	$8.1	372	6
3	Limerick	Transformer	PECO	$3.0	$0.6	$0.0	$2.4	$0.1	($3.8)	($0.0)	$3.8	$6.3	106	36
4	AP South	Interface	500	$2.1	$6.8	$0.1	($4.5)	($0.1)	$0.2	($0.0)	($0.4)	($4.9)	7,080	2,502
5	West	Interface	500	$4.7	$7.1	$0.0	($2.3)	($0.0)	$0.0	($0.0)	($0.0)	($2.4)	322	116
6	Bedington - Black Oak	Interface	500	$1.6	$3.6	$0.0	($2.0)	($0.0)	$0.1	($0.0)	($0.1)	($2.1)	3,704	222
7	Graceton - Raphael Road	Line	BGE	($1.5)	($3.6)	($0.0)	$2.0	$0.4	$0.4	$0.0	($0.0)	$2.0	682	468
8	Peachbottom	Transformer	PECO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($0.4)	($1.2)	($1.2)	0	28
9	Doubs	Transformer	AP	$0.9	$2.0	$0.0	($1.0)	($0.3)	($0.1)	($0.0)	($0.2)	($1.2)	2,492	896
10	East	Interface	500	$1.6	$0.4	($0.0)	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	370	16
11	Tiltonsville - Windsor	Line	AP	$1.5	$2.5	$0.0	($1.0)	($0.2)	($0.0)	($0.0)	($0.2)	($1.2)	5,204	940
12	East Frankfort - Crete	Line	ComEd	$1.9	$3.0	($0.0)	($1.1)	($0.1)	($0.1)	$0.0	$0.0	($1.1)	5,584	1,700
13	Plymouth Meeting - Whitpain	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.0)	($0.0)	$0.0	$0.0	$0.9	72	2
14	Keeney At5n	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	($0.4)	$0.5	($0.0)	($0.8)	($0.8)	52	26
15	Brandon Shores - Riverside	Line	BGE	$3.6	$4.0	$0.0	($0.4)	($0.2)	$0.2	($0.0)	($0.4)	($0.7)	686	324
21	Burlington - Croydon	Line	PECO	($0.2)	($0.6)	($0.0)	$0.4	$0.0	($0.1)	($0.0)	$0.1	$0.4	2,162	66
25	Eddystone - Saville	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	294	80
35	Jenkintown - Tabor	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.3)	0	20
55	Bradford - Planebrook	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.1	$0.1	0	2
57	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	28	0

PENELEC Control Zone

Table G-20 PENELEC Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($14.9)	($39.4)	($1.7)	$22.8	$1.7	$3.0	$2.5	$1.3	$24.1	1,810	940
2	AP South	Interface	500	($38.8)	($54.6)	($0.4)	$15.5	$2.7	$0.7	$0.9	$2.9	$18.4	8,222	2,026
3	West	Interface	500	($11.1)	($26.8)	($1.4)	$14.3	$0.0	$0.1	$0.1	$0.0	$14.3	1,734	40
4	Wylie Ridge	Transformer	AP	$8.1	$20.0	$0.8	($11.1)	($0.6)	($0.4)	($0.4)	($0.6)	($11.7)	3,836	760
5	Crete - St Johns Tap	Flowgate	MISO	$7.4	$10.0	$0.1	($2.5)	($0.3)	$0.2	($0.1)	($0.6)	($3.1)	6,708	2,230
6	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.5)	($0.1)	$2.6	$0.7	$0.6	$0.2	$0.2	$2.9	380	154
7	Johnstown - Seward	Line	PENELEC	$2.0	($0.6)	$0.0	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	102	0
8	Bedington - Black Oak	Interface	500	($5.1)	($7.5)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,358	14
9	Butler - Karns City	Line	AP	$5.5	$3.9	$0.3	$2.0	($0.2)	$0.0	($0.1)	($0.3)	$1.7	772	116
10	Susquehanna	Transformer	PPL	$0.5	($1.3)	($0.1)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	240	0
11	Yukon	Transformer	AP	$0.9	($0.9)	($0.0)	$1.8	($0.0)	$0.2	$0.0	($0.2)	$1.6	750	180
12	East	Interface	500	($2.4)	($4.2)	($0.3)	$1.5	$0.0	$0.1	$0.1	$0.0	$1.5	1,044	44
13	Graceton - Raphael Road	Line	BGE	($3.1)	($3.8)	($0.1)	$0.6	$0.2	$0.1	$0.1	$0.2	$0.8	2,314	830
14	East Frankfort - Crete	Line	ComEd	$2.9	$3.6	$0.1	($0.6)	$0.0	$0.1	($0.1)	($0.2)	($0.8)	3,092	658
15	Danville - East Danville	Line	AEP	$0.4	$1.2	($0.1)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	9,216	0
17	Laurel Lake - Tiffany	Line	PENELEC	$0.7	$0.1	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	154	0
23	Seward	Transformer	PENELEC	$0.4	$0.2	$0.0	$0.2	($0.2)	$0.5	($0.0)	($0.8)	($0.5)	42	44
26	East Towanda - S.Troy	Line	PENELEC	$0.2	$0.1	$0.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,440	0
28	Hooversville - Scalp Level	Line	PENELEC	$2.9	$2.1	$0.1	$0.8	($0.2)	$0.1	($0.1)	($0.4)	$0.5	434	110
35	Handsome Lake - Wayne	Line	PENELEC	$0.2	($0.2)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0

Table G-21 PENELEC Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($45.2)	($68.7)	($0.0)	$23.5	$4.1	($1.1)	$0.1	$5.2	$28.7	7,080	2,502
2	5004/5005 Interface	Interface	500	($10.8)	($35.5)	($0.1)	$24.5	$3.9	$1.8	$0.1	$2.3	$26.8	2,758	1,142
3	Bedington - Black Oak	Interface	500	($15.6)	($23.6)	($0.0)	$8.0	$0.2	($0.1)	$0.0	$0.4	$8.3	3,704	222
4	West	Interface	500	($3.6)	($8.7)	$0.0	$5.1	$0.2	$0.1	$0.0	$0.1	$5.2	322	116
5	Mount Storm - Pruntytown	Line	500	($3.4)	($5.6)	$0.0	$2.2	$2.3	($0.3)	$0.1	$2.7	$4.8	1,142	1,148
6	Seward	Transformer	PENELEC	$12.0	$7.2	$0.0	$4.8	($0.2)	$0.6	($0.0)	($0.8)	$4.0	742	126
7	Wylie Ridge	Transformer	AP	$0.9	$3.3	$0.1	($2.3)	($0.3)	$0.4	($0.1)	($0.8)	($3.1)	1,010	752
8	Bear Rock - Johnstown	Line	PENELEC	($2.1)	($4.1)	($0.0)	$1.9	$1.1	$0.0	$0.0	$1.1	$3.0	394	114
9	Tiltonsville - Windsor	Line	AP	$4.0	$5.9	$0.1	($1.8)	($0.9)	$0.2	($0.0)	($1.1)	($2.9)	5,204	940
10	Altoona - Bear Rock	Line	PENELEC	($2.4)	($4.7)	($0.0)	$2.3	$0.5	($0.1)	$0.0	$0.5	$2.8	496	110
11	East Frankfort - Crete	Line	ComEd	$5.5	$7.6	$0.0	($2.1)	($0.4)	$0.3	($0.0)	($0.7)	($2.8)	5,584	1,700
12	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.2	($0.1)	$0.0	$0.3	$2.1	942	178
13	Johnstown - Seward	Line	PENELEC	$2.7	$0.7	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	104	0
14	Doubs	Transformer	AP	($2.3)	($3.3)	$0.1	$1.1	$0.5	($0.1)	($0.0)	$0.6	$1.6	2,492	896
15	Hunterstown	Transformer	Met-Ed	($0.8)	($2.4)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	622	52
18	Homer City - Seward	Line	PENELEC	$4.6	$3.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	166	0
25	Keystone - Shelocta	Line	PENELEC	$3.0	$2.0	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	78	0
28	Blairsville - Shelocta	Line	PENELEC	$1.7	$1.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	48	0
30	Roxbury - Shade Gap	Line	PENELEC	($0.8)	($0.8)	($0.0)	($0.0)	$0.7	$1.3	$0.0	($0.6)	($0.6)	84	212
41	Clarks Summit - Eclipse	Line	PENELEC	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	128	0

Pepco Control Zone

Table G-22 Pepco Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$79.8	$58.9	$1.4	$22.2	($2.2)	($1.5)	($1.3)	($2.0)	$20.1	8,222	2,026
2	Dickerson - Quince Orchard	Line	Pepco	$27.8	$12.2	$0.2	$15.9	$0.5	$1.8	($0.2)	($1.5)	$14.4	284	152
3	West	Interface	500	$19.3	$13.3	$0.3	$6.2	($0.0)	($0.0)	($0.0)	$0.0	$6.3	1,734	40
4	Graceton - Raphael Road	Line	BGE	$11.4	$7.8	$0.1	$3.8	($0.2)	$0.0	($0.1)	($0.4)	$3.4	2,314	830
5	Wylie Ridge	Transformer	AP	$11.7	$8.6	$0.3	$3.5	($0.3)	($0.2)	($0.1)	($0.1)	$3.4	3,836	760
6	Bedington - Black Oak	Interface	500	$11.4	$8.4	$0.2	$3.2	($0.0)	($0.0)	($0.0)	$0.0	$3.2	1,358	14
7	Crete - St Johns Tap	Flowgate	MISO	$8.3	$5.8	$0.1	$2.7	($0.2)	($0.0)	($0.1)	($0.3)	$2.4	6,708	2,230
8	Danville - East Danville	Line	AEP	$7.3	$5.1	($0.0)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	9,216	0
9	AEP-DOM	Interface	500	$7.4	$5.6	$0.1	$2.0	($0.1)	($0.1)	$0.0	$0.0	$2.0	3,572	370
10	5004/5005 Interface	Interface	500	$5.8	$4.1	$0.1	$1.7	($0.0)	($0.1)	($0.1)	($0.1)	$1.6	1,810	940
11	East	Interface	500	($5.1)	($3.9)	($0.1)	($1.3)	$0.0	$0.1	$0.0	($0.1)	($1.4)	1,044	44
12	Gore - Hampshire	Line	AP	$4.3	$3.1	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,654	0
13	East Frankfort - Crete	Line	ComEd	$3.4	$2.2	$0.1	$1.3	($0.0)	($0.0)	($0.1)	($0.1)	$1.2	3,092	658
14	Burnham - Munster	Flowgate	MISO	$3.3	$2.4	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,304	0
15	Glenarm - Windy Edge	Line	BGE	$3.5	$2.5	$0.1	$1.1	($0.1)	($0.1)	($0.1)	($0.1)	$1.0	1,366	316
28	Pumphrey	Transformer	Pepco	($1.5)	($1.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	486	0
56	Burches Hill	Transformer	Pepco	$0.8	$0.5	$0.1	$0.4	$0.1	$0.0	($0.2)	($0.2)	$0.2	136	88
76	Buzzard - Ritchie	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	148	0
93	Burtonsville - Sandy Springs	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	24	0
199	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	($0.1)	($0.0)	26	20

Table G-23 Pepco Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$105.7	$78.2	$1.8	$29.3	($3.1)	($1.1)	($1.6)	($3.6)	$25.7	7,080	2,502
2	Bedington - Black Oak	Interface	500	$39.5	$27.7	$0.8	$12.5	($0.5)	($0.7)	($0.3)	($0.2)	$12.3	3,704	222
3	Doubs	Transformer	AP	$39.3	$24.9	$0.7	$15.1	($3.8)	$1.4	($1.7)	($6.8)	$8.2	2,492	896
4	Cloverdale - Lexington	Line	500	$10.6	$7.6	$0.1	$3.2	($0.9)	($0.9)	($0.3)	($0.3)	$2.9	2,138	1,356
5	Millville - Sleepy Hollow	Line	Dominion	$8.5	$6.1	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	802	0
6	Graceton - Raphael Road	Line	BGE	$7.5	$4.9	$0.2	$2.7	($0.7)	($0.6)	($0.2)	($0.3)	$2.4	682	468
7	Brandon Shores - Riverside	Line	BGE	($13.4)	($10.1)	($0.2)	($3.4)	$1.1	$0.4	$0.3	$1.1	($2.4)	686	324
8	East Frankfort - Crete	Line	ComEd	$6.2	$3.8	$0.0	$2.4	($0.3)	($0.1)	($0.0)	($0.2)	$2.3	5,584	1,700
9	Reid - Ringgold	Line	AP	$5.1	$3.1	$0.2	$2.2	($0.1)	($0.1)	($0.0)	$0.0	$2.2	652	84
10	5004/5005 Interface	Interface	500	$6.8	$4.6	$0.2	$2.4	($0.3)	($0.1)	($0.1)	($0.3)	$2.0	2,758	1,142
11	Mount Storm - Pruntytown	Line	500	$9.3	$6.6	$0.1	$2.7	($1.6)	($1.2)	($0.4)	($0.9)	$1.9	1,142	1,148
12	West	Interface	500	$5.9	$3.9	$0.0	$2.0	($0.1)	($0.1)	($0.0)	($0.1)	$1.8	322	116
13	AEP-DOM	Interface	500	$8.0	$6.6	$0.1	$1.5	($0.1)	($0.2)	($0.1)	($0.0)	$1.5	942	178
14	Tiltonsville - Windsor	Line	AP	$5.3	$3.5	$0.1	$1.8	($0.4)	($0.1)	($0.1)	($0.4)	$1.5	5,204	940
15	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	88	0
16	Bowie - Lanham	Line	Pepco	$2.2	$0.9	$0.1	$1.4	($0.3)	($0.2)	($0.1)	($0.2)	$1.1	72	26
19	Dickerson - Pleasant View	Line	Pepco	($2.4)	($1.5)	($0.0)	($1.0)	$0.1	$0.2	$0.1	($0.0)	($1.0)	370	194
25	Benning - Ritchie	Line	Pepco	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	156	0
33	Buzzard - Ritchie	Line	Pepco	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	116	2
42	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	18

PPL Control Zone

Table G-24 PPL Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$42.3	$53.4	$1.2	($10.0)	$1.8	$1.3	($0.8)	($0.2)	($10.2)	1,810	940
2	Susquehanna	Transformer	PPL	$16.5	$6.6	$0.2	$10.1	$0.0	$0.0	$0.0	$0.0	$10.1	240	0
3	West	Interface	500	$32.1	$38.0	$1.1	($4.8)	$0.0	($0.1)	($0.0)	$0.1	($4.7)	1,734	40
4	Harwood - Susquehanna	Line	PPL	$0.7	($3.0)	($0.1)	$3.7	($0.4)	$0.2	$0.1	($0.5)	$3.2	310	106
5	Graceton - Raphael Road	Line	BGE	($8.9)	($11.7)	($0.3)	$2.5	($0.1)	$0.1	$0.2	($0.0)	$2.5	2,314	830
6	Wylie Ridge	Transformer	AP	$14.0	$16.7	$0.4	($2.2)	$0.5	$0.1	($0.1)	$0.3	($1.9)	3,836	760
7	AP South	Interface	500	$0.4	($1.0)	$0.5	$1.8	$0.3	$0.1	($0.2)	$0.0	$1.9	8,222	2,026
8	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.4	$0.2	($0.0)	$0.2	($1.7)	6,708	2,230
9	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.1	($1.5)	($0.2)	$1.4	$1.4	0	104
10	Burnham - Munster	Flowgate	MISO	$3.0	$4.3	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	2,304	0
11	South Mahwah - Waldwick	Line	PSEG	$3.1	$3.9	$0.8	$0.0	$0.2	$0.3	($1.0)	($1.1)	($1.1)	10,538	988
12	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.4	($0.7)	($0.0)	$1.1	$1.1	0	30
13	East	Interface	500	($0.2)	($1.4)	($0.2)	$1.0	$0.0	$0.0	$0.1	$0.1	$1.0	1,044	44
14	Wescosville	Transformer	PPL	$1.6	$0.9	$0.0	$0.7	$0.3	$0.0	($0.0)	$0.3	$1.0	88	80
15	East Frankfort - Crete	Line	ComEd	$2.7	$3.6	$0.0	($0.9)	$0.0	($0.0)	($0.0)	$0.1	($0.8)	3,092	658
51	Mountain	Transformer	PPL	$0.1	($0.2)	$0.0	$0.2	($0.2)	$0.1	($0.1)	($0.4)	($0.1)	134	90
52	Elroy	Transformer	PPL	$0.5	$0.6	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	424	0
62	Juniata	Transformer	PPL	$0.8	$0.7	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	50	0
67	Dauphin - Juniata	Line	PPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0
68	Quarry - Steel City	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	12	34

Table G-25 PPL Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$32.8	$42.4	$0.9	($8.7)	$2.9	$1.4	($0.4)	$1.1	($7.6)	2,758	1,142
2	Brunner Island - Yorkana	Line	Met-Ed	($5.3)	($9.5)	($0.1)	$4.1	$0.3	$0.2	$0.1	$0.1	$4.2	474	360
3	West	Interface	500	$9.4	$12.2	$0.2	($2.7)	$0.1	$0.2	($0.1)	($0.2)	($2.8)	322	116
4	East Frankfort - Crete	Line	ComEd	$4.5	$6.8	($0.0)	($2.3)	$0.2	($0.2)	$0.0	$0.4	($1.8)	5,584	1,700
5	AP South	Interface	500	$2.8	$2.0	$0.5	$1.3	$0.3	($0.0)	($0.1)	$0.3	$1.6	7,080	2,502
6	Graceton - Raphael Road	Line	BGE	($4.7)	($6.6)	($0.1)	$1.8	($0.2)	$0.3	$0.0	($0.4)	$1.4	682	468
7	Harwood - Susquehanna	Line	PPL	$0.2	($1.4)	($0.0)	$1.6	$0.3	$0.5	($0.1)	($0.3)	$1.4	116	50
8	Millville - Sleepy Hollow	Line	Dominion	$2.4	$3.8	$0.1	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	802	0
9	Harwood - Siegfried	Line	PPL	($0.2)	($1.8)	$0.0	$1.5	($0.3)	$2.2	($0.1)	($2.6)	($1.1)	188	234
10	Juniata	Transformer	PENELEC	$0.0	$0.0	$0.1	$0.1	$0.7	$0.2	$0.4	$0.9	$1.0	92	54
11	Tiltonsville - Windsor	Line	AP	$3.7	$5.0	$0.1	($1.2)	$0.4	$0.2	($0.0)	$0.2	($1.0)	5,204	940
12	Eldred - Sunbury	Line	PPL	$0.6	($0.1)	$0.0	$0.7	$0.1	($0.1)	($0.0)	$0.1	$0.8	144	66
13	Crete - St Johns Tap	Flowgate	MISO	$1.9	$3.0	($0.0)	($1.1)	$0.1	($0.1)	$0.0	$0.2	($0.8)	1,782	622
14	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	78	0
15	East Palmerton - Siegfried	Line	PPL	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	140	0
19	East Palmerton - Harwood	Line	PPL	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	102	0
27	Frackville - Siegfried	Line	PPL	($0.1)	($0.5)	($0.0)	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	74	14
31	Eldred - Frackville	Line	PPL	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	40	0
35	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.2	($0.1)	($0.3)	($0.3)	22	34
47	Juniata	Transformer	PPL	$0.5	$0.4	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	64	0

PSEG Control Zone

Table G-26 PSEG Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	$29.5	$14.6	($7.0)	$7.9	($1.9)	$3.9	($13.0)	($18.8)	($10.9)	10,538	988
2	Waldwick	Transformer	PSEG	$2.1	$1.1	$1.4	$2.4	($0.6)	$0.5	($7.6)	($8.7)	($6.4)	296	186
3	Cedar Grove - Roseland	Line	PSEG	$9.2	$3.9	$0.2	$5.5	($0.1)	$0.7	($0.2)	($0.9)	$4.6	1,812	74
4	AP South	Interface	500	($1.0)	$3.3	$1.5	($2.8)	$0.1	($0.2)	($1.6)	($1.2)	($4.0)	8,222	2,026
5	West	Interface	500	$36.3	$33.9	$1.4	$3.8	($0.1)	$0.1	($0.0)	($0.2)	$3.6	1,734	40
6	Bayway - Federal Square	Line	PSEG	$2.0	($0.6)	$0.2	$2.9	($0.0)	$0.0	($0.0)	($0.1)	$2.8	2,286	30
7	Branchburg - Readington	Line	PSEG	$3.6	$1.2	$0.3	$2.7	($0.1)	$0.4	($0.2)	($0.7)	$2.0	936	108
8	5004/5005 Interface	Interface	500	$33.3	$31.8	$1.5	$2.9	$1.4	$4.4	($1.7)	($4.7)	($1.8)	1,810	940
9	Susquehanna	Transformer	PPL	$1.5	$0.2	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	240	0
10	Roseland - Whippany	Line	PSEG	$2.5	$1.1	$0.3	$1.6	($0.0)	$0.0	($0.4)	($0.5)	$1.2	684	112
11	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	$0.6	$0.0	($1.2)	$0.1	($0.1)	($0.0)	$0.1	($1.1)	412	144
12	Redoak - Sayreville	Line	JCPL	$1.1	$0.1	$0.1	$1.1	($0.0)	$0.0	($0.0)	($0.0)	$1.1	3,504	22
13	Graceton - Raphael Road	Line	BGE	($8.6)	($8.9)	($0.5)	($0.2)	$0.2	($0.5)	$0.4	$1.2	$0.9	2,314	830
14	Wylie Ridge	Transformer	AP	$12.2	$12.4	$0.7	$0.5	$0.0	$1.0	($0.4)	($1.4)	($0.9)	3,836	760
15	Camden	Transformer	PSEG	$0.9	$0.2	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	840	0
16	Bridgewater - Middlesex	Line	PSEG	$0.5	$0.3	$0.1	$0.3	$0.0	$0.7	($0.4)	($1.1)	($0.8)	1,108	126
17	Hawthorn - Waldwick	Line	PSEG	$0.2	$0.1	$0.6	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,318	0
18	Roseland - West Caldwell	Line	PSEG	$1.5	$0.5	$0.1	$1.1	($0.0)	$0.3	($0.2)	($0.4)	$0.7	264	58
23	Montville - Roseland	Line	PSEG	$1.1	$0.6	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	126	0
24	Athenia - Saddlebrook	Line	PSEG	$0.9	$0.6	$0.3	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	2,796	8

Table G-27 PSEG Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Branchburg - Readington	Line	PSEG	$8.9	$1.2	$0.6	$8.3	$0.1	$1.0	($0.5)	($1.4)	$6.9	2,434	368
2	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.7)	($3.4)	($3.4)	908	78
3	Athenia - Saddlebrook	Line	PSEG	$12.6	$2.5	$7.5	$17.6	($6.8)	$2.5	($5.0)	($14.3)	$3.3	5,918	662
4	AP South	Interface	500	$1.1	$5.4	$2.4	($1.9)	$0.2	($0.3)	($1.5)	($1.0)	($2.9)	7,080	2,502
5	Hillsdale - New Milford	Line	PSEG	$1.1	$0.5	$1.6	$2.2	$0.0	$0.0	($0.1)	($0.1)	$2.1	1,570	46
6	Eddystone - Island Road	Line	PECO	$1.0	($0.7)	$0.0	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	372	6
7	5004/5005 Interface	Interface	500	$24.1	$23.1	$2.0	$3.0	$2.0	$1.6	($1.8)	($1.4)	$1.6	2,758	1,142
8	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	418	70
9	Redoak - Sayreville	Line	JCPL	$1.2	($0.3)	$0.1	$1.5	$0.0	($0.0)	($0.0)	$0.0	$1.5	1,700	114
10	North Ave - Pvsc	Line	PSEG	$0.2	($0.8)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	1,328	0
11	Bedington - Black Oak	Interface	500	$1.8	$3.6	$0.9	($0.9)	($0.0)	$0.0	($0.2)	($0.2)	($1.0)	3,704	222
12	Brandon Shores - Riverside	Line	BGE	$5.7	$5.0	$0.3	$1.0	$0.4	$0.1	($0.3)	$0.0	$1.0	686	324
13	Bayway - Federal Square	Line	PSEG	$0.6	($0.4)	$0.0	$1.0	($0.0)	$0.0	($0.0)	($0.0)	$1.0	1,088	16
14	Graceton - Raphael Road	Line	BGE	($4.5)	($4.6)	($0.2)	($0.2)	$0.2	($0.5)	$0.3	$1.0	$0.8	682	468
15	Doubs	Transformer	AP	$1.5	$1.4	$0.3	$0.4	($0.2)	$0.4	($0.6)	($1.3)	($0.8)	2,492	896
16	Bergen - Hoboken	Line	PSEG	$0.1	($0.2)	$0.4	$0.7	($0.2)	($0.1)	$0.1	$0.1	$0.8	1,004	58
19	Leonia - New Milford	Line	PSEG	$0.4	$0.3	$0.8	$0.9	($0.0)	$0.1	($0.0)	($0.2)	$0.7	2,172	12
21	Bayonne - PVSC	Line	PSEG	$0.0	($0.5)	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	1,360	0
25	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	340	0
28	Fairlawn - Saddlebrook	Line	PSEG	$0.4	$0.2	$0.7	$0.9	($0.0)	$0.1	($0.4)	($0.5)	$0.4	996	34

RECO Control Zone

Table G-28 RECO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	($1.5)	($0.6)	($0.0)	($0.9)	($0.0)	$1.0	$0.0	($1.0)	($1.9)	10,538	988
2	West	Interface	500	$1.0	$0.0	$0.0	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,734	40
3	5004/5005 Interface	Interface	500	$0.9	$0.1	$0.0	$0.8	$0.0	($0.1)	($0.0)	$0.1	$0.9	1,810	940
4	Waldwick	Transformer	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	$0.0	($0.4)	($0.5)	296	186
5	East	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,044	44
6	Wylie Ridge	Transformer	AP	$0.3	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,836	760
7	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	1,812	74
8	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	6,708	2,230
9	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,314	830
10	Dickerson - Quince Orchard	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.2	284	152
11	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	8,222	2,026
12	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	936	108
13	Burnham - Munster	Flowgate	MISO	$0.1	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,304	0
14	Glenarm - Windy Edge	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.1)	1,366	316
15	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,092	658

Table G-29 RECO Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$0.9	$0.1	$0.0	$0.8	$0.2	($0.1)	($0.0)	$0.3	$1.1	2,758	1,142
2	Branchburg - Readington	Line	PSEG	$0.6	$0.0	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	2,434	368
3	West	Interface	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	322	116
4	Brandon Shores - Riverside	Line	BGE	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	686	324
5	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.2)	7,080	2,502
6	Athenia - Saddlebrook	Line	PSEG	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.1)	$0.0	$0.1	$0.2	5,918	662
7	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.1)	($0.2)	682	468
8	Tiltonsville - Windsor	Line	AP	$0.2	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	5,204	940
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	5,584	1,700
10	Brunner Island - Yorkana	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	474	360
11	Hillsdale - New Milford	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	1,570	46
12	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	908	78
13	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	418	70
14	Millville - Sleepy Hollow	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	802	0
15	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	2,470	896

Western Region Congestion-Event Summaries

AEP Control Zone

Table G-30 AEP Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($113.5)	($148.9)	($1.3)	$34.1	$3.7	$6.9	$2.3	($1.0)	$33.1	8,222	2,026
2	Belmont	Transformer	AP	$13.1	($15.0)	$4.9	$33.1	($2.0)	($0.3)	($3.9)	($5.6)	$27.5	8,742	998
3	AEP-DOM	Interface	500	($13.9)	($37.1)	$2.5	$25.7	$0.6	$1.5	($0.7)	($1.6)	$24.1	3,572	370
4	Brues - West Bellaire	Line	AEP	$21.7	$6.3	$1.9	$17.3	($2.1)	$1.7	($2.0)	($5.8)	$11.5	3,436	1,196
5	5004/5005 Interface	Interface	500	($65.3)	($76.4)	($0.8)	$10.3	$2.9	$3.9	$1.3	$0.3	$10.7	1,810	940
6	West	Interface	500	($56.9)	($68.0)	($0.6)	$10.4	$0.0	$0.1	$0.0	($0.0)	$10.4	1,734	40
7	Breed - Wheatland	Line	AEP	$1.2	($7.4)	($1.0)	$7.6	($0.0)	($0.0)	($0.0)	$0.0	$7.6	2,436	2
8	Danville - East Danville	Line	AEP	($30.1)	($29.9)	($5.4)	($5.6)	$0.0	$0.0	$0.0	$0.0	($5.6)	9,216	0
9	Michigan City - Laporte	Flowgate	MISO	$15.2	$8.9	$4.3	$10.6	($3.1)	($1.7)	($3.9)	($5.4)	$5.2	5,870	1,264
10	Kammer	Transformer	AEP	$5.5	($2.8)	$1.2	$9.4	($3.4)	($0.3)	($1.3)	($4.4)	$5.1	2,532	138
11	Wolfcreek	Transformer	AEP	($8.9)	($14.2)	$1.4	$6.7	($0.1)	$0.5	($1.2)	($1.9)	$4.8	5,094	452
12	Wylie Ridge	Transformer	AP	($42.9)	($49.0)	($1.3)	$4.8	$0.5	$1.3	$0.6	($0.2)	$4.6	3,836	760
13	Bedington - Black Oak	Interface	500	($16.5)	($20.8)	($0.1)	$4.2	$0.1	$0.0	$0.0	$0.0	$4.2	1,358	14
14	Cloverdale	Transformer	AEP	($4.5)	($8.8)	$0.4	$4.7	$0.2	$0.8	($0.0)	($0.7)	$4.1	1,402	250
15	Muskingum River	Transformer	AEP	($0.5)	($3.9)	$0.5	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	636	0
17	Marquis - Dept of Energy	Line	AEP	$0.1	($0.3)	$3.2	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,996	0
19	Muskingum River - East New Concord	Line	AEP	$0.7	($1.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	218	0
21	Jefferson - Clifty Creek	Line	AEP	($0.1)	($3.1)	($0.4)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	538	0
23	Carbondale - Kanawha River	Line	AEP	($3.5)	($5.6)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	548	0
25	Muskingum River - Waterford	Line	AEP	($1.0)	($2.8)	$1.5	$3.3	$0.2	$0.8	($0.5)	($1.1)	$2.2	1,028	106

Table G-31 AEP Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($32.6)	($81.3)	$0.4	$49.1	($3.4)	$2.5	$1.1	($4.9)	$44.2	7,080	2,502
2	AEP-DOM	Interface	500	$7.5	($20.1)	$1.0	$28.5	($0.2)	($0.3)	($0.3)	($0.1)	$28.4	942	178
3	Bedington - Black Oak	Interface	500	($12.3)	($26.5)	$0.1	$14.4	($0.1)	$0.1	$0.2	$0.0	$14.4	3,704	222
4	5004/5005 Interface	Interface	500	($17.8)	($27.1)	($0.4)	$8.9	($0.1)	$2.7	$0.6	($2.3)	$6.6	2,758	1,142
5	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	20	148
6	Belmont	Transformer	AP	$3.8	($0.8)	$0.7	$5.3	$0.2	($0.1)	($0.5)	($0.2)	$5.1	2,166	218
7	Kanawha River	Transformer	AEP	$2.7	($0.5)	$0.5	$3.7	$0.0	($0.0)	($0.0)	$0.0	$3.7	380	22
8	Brues - West Bellaire	Line	AEP	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.9	($0.2)	($3.2)	($3.2)	0	156
9	Mahans Lane - Tidd	Line	AEP	($1.4)	($4.7)	($0.3)	$3.0	$0.2	$0.1	$0.0	$0.2	$3.2	1,292	414
10	Mount Storm - Pruntytown	Line	500	($2.9)	($8.0)	($0.1)	$5.0	($0.8)	$1.5	$0.5	($1.9)	$3.1	1,142	1,148
11	West	Interface	500	($5.6)	($9.0)	($0.1)	$3.3	($0.2)	$0.3	$0.1	($0.4)	$2.9	322	116
12	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	440	0
13	Doubs	Transformer	AP	($10.8)	($13.8)	($0.2)	$2.8	$0.0	$0.9	$0.3	($0.6)	$2.2	2,492	896
14	Electric Jct - Nelson	Line	ComEd	$0.4	$0.6	$5.7	$5.5	($0.1)	($0.0)	($7.3)	($7.4)	($1.9)	2,908	482
15	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	92	0
18	Kammer - Natrium	Line	AEP	$1.5	($0.4)	$0.2	$2.0	($0.3)	$0.0	($0.1)	($0.4)	$1.6	614	96
20	Breed - Wheatland	Line	AEP	$0.0	($1.6)	($0.1)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	300	2
22	Sullivan	Transformer	AEP	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	370	94
23	Ruth - Turner	Line	AEP	$0.8	($0.4)	$0.1	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	242	92
24	Cloverdale - Ivy Hill	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.1)	$0.1	$0.0	($1.2)	($1.2)	0	222

AP Control Zone

Table G-32 AP Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($26.3)	($91.6)	($7.8)	$57.6	$5.5	$5.7	$6.5	$6.3	$63.9	8,222	2,026
2	Belmont	Transformer	AP	$34.3	$7.2	$0.9	$28.0	($2.4)	($3.3)	($0.6)	$0.3	$28.3	8,742	998
3	5004/5005 Interface	Interface	500	($20.2)	($29.7)	($3.8)	$5.7	$1.4	$1.7	$4.4	$4.0	$9.7	1,810	940
4	Bedington - Black Oak	Interface	500	($3.1)	($11.6)	($1.9)	$6.5	$0.0	$0.1	$0.1	$0.1	$6.6	1,358	14
5	Yukon	Transformer	AP	$4.4	$0.0	$0.2	$4.6	$0.2	$0.4	($0.1)	($0.3)	$4.3	750	180
6	AEP-DOM	Interface	500	($1.3)	($4.7)	($0.0)	$3.3	$0.1	$0.1	$0.3	$0.4	$3.7	3,572	370
7	Bedington	Transformer	AP	$1.2	($2.7)	($0.2)	$3.6	($0.1)	$0.6	$0.3	($0.4)	$3.2	464	206
8	Wylie Ridge	Transformer	AP	$6.0	$9.7	$3.7	($0.0)	($0.1)	($0.3)	($3.1)	($2.9)	($2.9)	3,836	760
9	West	Interface	500	($18.5)	($24.4)	($3.2)	$2.6	$0.1	$0.0	$0.1	$0.1	$2.8	1,734	40
10	Wolfcreek	Transformer	AEP	$5.7	$8.2	$1.0	($1.5)	($0.5)	($0.6)	($1.0)	($0.9)	($2.4)	5,094	452
11	Tiltonsville - Windsor	Line	AP	$2.6	$0.7	$0.3	$2.1	($0.2)	($0.0)	($0.2)	($0.4)	$1.7	2,008	144
12	Dickerson - Quince Orchard	Line	Pepco	($6.8)	($5.2)	($0.9)	($2.5)	($0.8)	($0.2)	$1.3	$0.8	($1.7)	284	152
13	Mount Storm	Line	AP	($0.4)	($1.9)	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	162	0
14	Danville - East Danville	Line	AEP	$0.3	($1.1)	$0.2	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	9,216	0
15	Valley	Transformer	Dominion	($0.8)	($2.0)	($0.0)	$1.2	$0.3	$0.2	$0.1	$0.2	$1.4	438	196
16	Gore - Hampshire	Line	AP	($2.1)	($3.8)	($0.4)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,654	0
19	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.6	$1.1	($0.6)	($1.1)	($1.1)	0	218
21	Kingwood - Pruntytown	Line	AP	$0.8	($0.1)	$0.1	$0.9	($0.0)	($0.1)	($0.0)	($0.0)	$0.9	404	28
25	Hamilton - Weirton	Line	AP	$1.0	$0.3	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	304	6
26	Halfway - Marlowe	Line	AP	$0.5	($0.2)	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	158	18

Table G-33 AP Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($30.8)	($119.2)	($8.3)	$80.1	$5.3	$6.2	$7.4	$6.4	$86.5	7,080	2,502
2	Doubs	Transformer	AP	$13.6	($10.3)	($0.2)	$23.7	$3.4	$0.9	$0.1	$2.7	$26.3	2,492	896
3	Bedington - Black Oak	Interface	500	($10.2)	($38.1)	($1.8)	$26.0	$0.3	$1.9	$0.1	($1.5)	$24.6	3,704	222
4	Tiltonsville - Windsor	Line	AP	$17.1	$3.9	$1.5	$14.8	($2.6)	($0.7)	($1.7)	($3.6)	$11.2	5,204	940
5	Mount Storm - Pruntytown	Line	500	($2.8)	($11.1)	($0.4)	$7.9	$2.5	$1.7	$2.0	$2.8	$10.6	1,142	1,148
6	5004/5005 Interface	Interface	500	($17.1)	($26.2)	($1.4)	$7.7	$2.0	$2.9	$1.4	$0.6	$8.3	2,758	1,142
7	Belmont	Transformer	AP	$7.3	($0.7)	$0.2	$8.2	($0.2)	($0.3)	($0.2)	($0.1)	$8.1	2,166	218
8	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.4	$6.0	$0.3	($0.2)	($0.1)	$0.4	$6.4	942	178
9	Kingwood - Pruntytown	Line	AP	$5.4	$1.4	$0.6	$4.6	$0.0	($0.1)	($0.2)	($0.0)	$4.6	996	98
10	Cloverdale - Lexington	Line	500	$1.4	($3.4)	$0.9	$5.7	($0.1)	$0.4	($1.8)	($2.3)	$3.4	2,138	1,356
11	Endless Caverns	Transformer	Dominion	$2.6	$0.0	$0.3	$2.9	$0.0	$0.0	($0.0)	($0.0)	$2.9	1,082	6
12	Nipetown - Reid	Line	AP	$0.0	($2.6)	($0.0)	$2.5	$0.1	$0.2	($0.0)	($0.1)	$2.5	642	126
13	Mahans Lane - Tidd	Line	AEP	$3.9	$1.4	$0.4	$2.9	($0.4)	($0.1)	($0.2)	($0.5)	$2.4	1,292	414
14	Fort Martin - Ronco	Line	AP	$0.2	$0.2	$0.1	$0.2	($0.2)	$0.9	($1.4)	($2.5)	($2.3)	62	84
15	Middlebourne - Willow	Line	AP	$2.0	($0.2)	$0.3	$2.5	($0.2)	($0.1)	($0.2)	($0.3)	$2.1	634	162
17	Wylie Ridge	Transformer	AP	$0.9	$1.5	$0.6	$0.0	($0.7)	($0.2)	($1.4)	($1.9)	($1.9)	1,010	752
18	Hamilton - Weirton	Line	AP	$2.7	$0.9	$0.2	$2.0	($0.1)	$0.1	($0.1)	($0.3)	$1.7	900	36
19	Yukon	Transformer	AP	$1.7	$0.1	$0.1	$1.7	$0.0	$0.1	$0.1	($0.0)	$1.7	224	34
20	Halfway - Marlowe	Line	AP	$0.6	($0.7)	($0.0)	$1.3	$0.2	($0.1)	$0.0	$0.2	$1.5	120	40
21	Bedington - Shepherdstown	Line	AP	($0.0)	($1.2)	$0.1	$1.3	$0.1	($0.1)	$0.0	$0.2	$1.5	1,100	90

ATSI Control Zone

Table G-34 ATSI Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($27.8)	($27.1)	($1.3)	($2.0)	($0.2)	$2.4	$1.8	($0.8)	($2.9)	8,222	2,026
2	Niles - Evergreen	Line	ATSI	$3.2	$0.8	$0.8	$3.2	($0.4)	$0.2	($0.6)	($1.2)	$1.9	892	54
3	Dickerson - Quince Orchard	Line	Pepco	($4.2)	($3.5)	$0.0	($0.7)	($0.2)	$0.4	($0.0)	($0.6)	($1.3)	284	152
4	West	Interface	500	($21.8)	($20.7)	($0.1)	($1.2)	($0.0)	$0.0	$0.0	($0.0)	($1.2)	1,734	40
5	Bayshore - Jeep	Line	ATSI	$0.8	($0.2)	$0.0	$1.0	$0.4	$0.2	$0.0	$0.2	$1.2	32	12
6	Clover	Transformer	Dominion	($2.8)	($2.3)	$0.4	($0.2)	$0.2	$0.4	($0.6)	($0.8)	($1.0)	2,476	938
7	Beaver - Sammis	Line	DLCO	($0.5)	($1.5)	($0.1)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	442	22
8	Burnham - Munster	Flowgate	MISO	$4.5	$3.7	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	2,304	0
9	South Canton - Torrey	Line	AEP	$1.4	$0.6	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	82	16
10	Danville - East Danville	Line	AEP	($3.8)	($3.3)	($0.2)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	9,216	0
11	5004/5005 Interface	Interface	500	($5.0)	($5.1)	($0.1)	($0.0)	$0.2	$1.2	$0.2	($0.7)	($0.8)	1,810	940
12	Muskingum River - Waterford	Line	AEP	$0.8	$0.7	$0.1	$0.1	$0.1	($0.1)	($1.0)	($0.7)	($0.6)	1,028	106
13	AEP-DOM	Interface	500	($4.4)	($3.8)	($0.1)	($0.8)	$0.0	$0.1	$0.2	$0.2	($0.6)	3,572	370
14	Benton Harbor - Palisades	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.4)	($0.6)	($0.6)	134	264
15	Jeep - Dixie	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	28	0
20	Sammis - Wylie Ridge	Line	ATSI	($1.2)	($1.8)	($0.2)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	484	8
29	Lakeview - Ottawa	Line	ATSI	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.3	46	4
31	Galion – GM Mansfield	Line	ATSI	$0.3	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	36	0
35	Galion - Leaside	Line	ATSI	$0.1	$0.1	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	44	22
42	Brookside - Wellington	Line	ATSI	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	224	0

ComEd Control Zone

Table G-35 ComEd Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Electric Jct - Nelson	Line	ComEd	($5.1)	($43.6)	$6.2	$44.8	$1.2	$4.0	($5.1)	($7.9)	$36.9	5,852	316
2	Crete - St Johns Tap	Flowgate	MISO	($156.4)	($190.6)	($16.6)	$17.6	$7.0	$5.6	$7.6	$8.9	$26.5	6,708	2,230
3	AP South	Interface	500	($122.0)	($134.5)	($0.9)	$11.6	$7.6	$2.5	$0.3	$5.5	$17.1	8,222	2,026
4	East Frankfort - Crete	Line	ComEd	($56.3)	($71.2)	($5.0)	$10.0	$1.5	$0.5	$2.1	$3.1	$13.1	3,092	658
5	Bunsonville - Eugene	Flowgate	MISO	($39.8)	($51.0)	($0.1)	$11.1	$0.0	$0.0	($0.0)	($0.0)	$11.1	4,888	22
6	Pleasant Valley - Belvidere	Line	ComEd	($5.3)	($17.4)	$1.2	$13.3	($0.3)	$2.2	($1.3)	($3.8)	$9.5	2,186	630
7	5004/5005 Interface	Interface	500	($62.7)	($69.3)	($0.4)	$6.2	$4.0	$2.0	$0.5	$2.5	$8.7	1,810	940
8	Wylie Ridge	Transformer	AP	($38.5)	($43.2)	($0.1)	$4.6	$1.6	$0.4	($0.1)	$1.1	$5.7	3,836	760
9	Michigan City - Laporte	Flowgate	MISO	($40.7)	($43.4)	$1.7	$4.3	$2.5	$0.5	($1.0)	$1.0	$5.4	5,870	1,264
10	Lakeview - Pleasant Prairie	Flowgate	MISO	$0.3	$0.2	$0.2	$0.3	($0.3)	($0.0)	($4.8)	($5.1)	($4.8)	48	604
11	Brokaw - Gibson	Flowgate	MISO	($15.1)	($19.7)	$0.5	$5.2	$0.2	$0.1	($0.6)	($0.5)	$4.7	1,418	190
12	Waukegan - Zion	Line	ComEd	$0.7	($1.2)	$2.9	$4.8	$0.0	$0.0	($0.3)	($0.3)	$4.5	3,468	14
13	Rantoul - Rantoul Jct	Flowgate	MISO	($14.3)	($18.3)	$0.0	$3.9	$0.3	$0.1	$0.1	$0.3	$4.2	1,106	376
14	Cherry Valley	Transformer	ComEd	$1.7	($1.8)	$0.5	$3.9	$0.1	$0.1	($0.2)	($0.2)	$3.7	1,406	164
15	West	Interface	500	($59.0)	($62.7)	($0.2)	$3.5	$0.1	$0.1	$0.0	$0.1	$3.6	1,734	40
16	Glidden - West Dekalb	Line	ComEd	($0.7)	($3.9)	$0.3	$3.5	$0.0	($0.0)	($0.0)	($0.0)	$3.5	2,236	2
19	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$1.2	($0.1)	$1.7	$3.0	$3.0	0	454
21	Wilton Center	Transformer	ComEd	($1.6)	($1.9)	$2.5	$2.8	$0.1	$0.1	$0.0	$0.0	$2.9	134	52
23	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.0)	$0.3	$3.3	$0.0	$0.2	($0.2)	($0.5)	$2.8	378	86
25	Woodstock - 12205	Line	ComEd	($0.7)	($3.1)	$0.2	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	790	0

Table G-36 ComEd Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	East Frankfort - Crete	Line	ComEd	($43.4)	($81.0)	($5.2)	$32.4	($3.7)	($1.1)	$1.2	($1.4)	$31.0	5,584	1,700
2	Electric Jct - Nelson	Line	ComEd	$1.1	($24.4)	$6.5	$32.1	$1.3	$3.7	($7.7)	($10.1)	$22.0	2,908	482
3	AP South	Interface	500	($73.8)	($99.1)	($0.7)	$24.6	($3.2)	($0.5)	($0.0)	($2.7)	$21.8	7,080	2,502
4	Crete - St Johns Tap	Flowgate	MISO	($22.3)	($36.7)	($1.7)	$12.8	($1.2)	($1.4)	$0.6	$0.8	$13.6	1,782	622
5	Pleasant Valley - Belvidere	Line	ComEd	($3.3)	($19.8)	$1.8	$18.3	$0.1	$2.7	($2.4)	($5.0)	$13.3	4,110	830
6	Nelson - Cordova	Line	ComEd	$8.1	($2.8)	$3.5	$14.3	$0.8	$1.7	($3.5)	($4.4)	$9.9	2,516	190
7	Bedington - Black Oak	Interface	500	($26.2)	($34.5)	($0.2)	$8.2	($0.7)	($0.2)	$0.0	($0.5)	$7.7	3,704	222
8	Waterman - West Dekalb	Line	ComEd	($1.6)	($7.4)	$0.8	$6.5	$0.4	$0.3	($0.2)	($0.0)	$6.5	5,216	576
9	5004/5005 Interface	Interface	500	($25.2)	($35.1)	($0.1)	$9.8	($4.3)	($0.7)	$0.2	($3.3)	$6.4	2,758	1,142
10	AEP-DOM	Interface	500	($10.3)	($16.3)	($0.4)	$5.6	($0.1)	($0.2)	$0.0	$0.1	$5.7	942	178
11	Rising	Flowgate	MISO	($2.2)	($6.9)	($0.0)	$4.7	($0.0)	$0.0	$0.0	($0.0)	$4.6	1,552	90
12	Cloverdale - Lexington	Line	500	($11.2)	($17.3)	($0.4)	$5.7	($1.7)	($0.2)	$0.4	($1.1)	$4.5	2,138	1,356
13	Glidden - West Dekalb	Line	ComEd	($0.2)	($3.8)	$0.4	$4.1	$0.0	$0.0	($0.0)	($0.0)	$4.1	1,520	4
14	Tiltonsville - Windsor	Line	AP	($10.9)	($14.7)	($0.3)	$3.6	($1.4)	($0.1)	$0.4	($0.9)	$2.7	5,204	940
15	Doubs	Transformer	AP	($15.2)	($19.1)	($0.1)	$3.8	($1.1)	$0.5	$0.1	($1.5)	$2.3	2,492	896
17	Cherry Valley	Transformer	ComEd	$0.9	($1.1)	$0.2	$2.1	$0.1	$0.1	($0.1)	($0.1)	$2.0	214	74
22	Electric Junction - Aurora	Line	ComEd	$1.3	$0.2	$0.0	$1.1	$0.0	$0.1	$0.1	$0.1	$1.2	272	70
23	Woodstock - 12205	Line	ComEd	($0.0)	($1.0)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	182	0
29	Belvidere - Woodstock	Line	ComEd	$0.3	($0.6)	$0.1	$0.9	$0.0	$0.1	($0.0)	($0.0)	$0.9	186	14
36	Burnham - Munster	Line	ComEd	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	2	164

DAY Control Zone

Table G-37 DAY Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pierce - Foster	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.2)	($1.7)	($1.6)	($1.6)	0	40
2	West	Interface	500	($7.3)	($8.7)	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,734	40
3	AP South	Interface	500	($16.1)	($17.7)	($0.4)	$1.2	$0.8	$1.5	$0.5	($0.2)	$1.0	8,222	2,026
4	AEP-DOM	Interface	500	($3.7)	($4.7)	($0.0)	$0.9	$0.1	$0.2	$0.1	$0.0	$0.9	3,572	370
5	Danville - East Danville	Line	AEP	($2.5)	($3.4)	($0.1)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	9,216	0
6	Burnham - Munster	Flowgate	MISO	$1.1	$1.7	$0.1	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	2,304	0
7	Clover	Transformer	Dominion	($1.9)	($2.4)	$0.1	$0.6	$0.2	$0.2	($0.1)	($0.1)	$0.5	2,476	938
8	Crete - St Johns Tap	Flowgate	MISO	$2.8	$3.1	($0.1)	($0.4)	($0.1)	($0.1)	($0.2)	($0.1)	($0.5)	6,708	2,230
9	East Frankfort - Crete	Line	ComEd	$1.0	$1.4	$0.1	($0.3)	($0.0)	$0.0	($0.1)	($0.1)	($0.5)	3,092	658
10	Breed - Wheatland	Line	AEP	$0.5	$0.9	($0.0)	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.4)	2,436	2
11	Wolfcreek	Transformer	AEP	($1.7)	($2.1)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	5,094	452
12	Bunsonville - Eugene	Flowgate	MISO	$1.7	$2.2	$0.1	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	4,888	22
13	Valley	Transformer	Dominion	($0.9)	($1.3)	($0.0)	$0.4	$0.1	$0.2	$0.0	($0.0)	$0.3	438	196
14	Belmont	Transformer	AP	($1.5)	($1.8)	$0.1	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	8,742	998
15	Brokaw - Gibson	Flowgate	MISO	$0.4	$0.8	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.0)	($0.3)	1,418	190
37	Trenton - Hutchings	Line	DAY	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	106	0
153	Foster2 - Pierce	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	2

Table G-38 DAY Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($1.4)	($2.5)	($0.2)	$0.9	$0.3	$0.0	$0.4	$0.7	$1.6	2,758	1,142
2	AP South	Interface	500	($4.5)	($6.2)	($0.9)	$0.8	$0.1	$0.5	$0.6	$0.2	$1.0	7,080	2,502
3	Cloverdale - Lexington	Line	500	($0.5)	($1.4)	($0.2)	$0.6	$0.1	($0.0)	$0.2	$0.3	$1.0	2,138	1,356
4	Pleasant Prairie - Zion	Flowgate	MISO	$0.0	($0.0)	$0.5	$0.5	($0.0)	$0.0	($1.4)	($1.4)	($0.9)	2,196	618
5	Mount Storm - Pruntytown	Line	500	($0.4)	($0.5)	($0.0)	$0.1	$0.2	$0.3	$0.7	$0.6	$0.7	1,142	1,148
6	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	942	178
7	Tiltonsville - Windsor	Line	AP	($0.7)	($1.0)	($0.3)	$0.1	$0.1	$0.0	$0.4	$0.5	$0.5	5,204	940
8	Harrison - Pruntytown	Line	500	($0.1)	($0.2)	($0.0)	$0.0	$0.1	$0.1	$0.4	$0.4	$0.5	462	446
9	Doubs	Transformer	AP	($0.9)	($1.3)	($0.1)	$0.3	$0.1	$0.1	$0.1	$0.1	$0.4	2,492	896
10	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	0
11	Waterman - West Dekalb	Line	ComEd	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.1)	($0.1)	$0.4	5,216	576
12	Pleasant Valley - Belvidere	Line	ComEd	$0.0	$0.0	$0.8	$0.8	($0.0)	$0.0	($1.2)	($1.2)	($0.4)	4,110	830
13	Bedington - Black Oak	Interface	500	($1.4)	($2.2)	($0.4)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	3,704	222
14	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.4	($0.1)	($0.2)	($0.0)	$0.1	($0.0)	($0.1)	($0.3)	1,782	622
15	Clover	Transformer	Dominion	($0.2)	($0.5)	$0.1	$0.3	$0.0	($0.0)	($0.1)	$0.0	$0.3	1,004	516

DLCO Control Zone

Table G-39 DLCO Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$5.9	($0.4)	$0.1	$6.4	($0.1)	$0.1	($0.2)	($0.4)	$6.0	714	206
2	Wylie Ridge	Transformer	AP	($11.5)	($16.8)	($0.4)	$4.8	($0.4)	($0.1)	$0.2	($0.2)	$4.7	3,836	760
3	AP South	Interface	500	($18.6)	($23.3)	($0.5)	$4.1	($1.3)	$0.0	$0.4	($0.9)	$3.3	8,222	2,026
4	Collier - Elwyn	Line	DLCO	$1.8	($0.2)	$0.0	$2.0	$0.1	$0.1	($0.0)	($0.0)	$1.9	504	60
5	Brunot Island - Forbes	Line	DLCO	$0.7	($0.1)	$0.0	$0.8	($0.0)	($0.1)	($0.0)	$0.0	$0.8	172	72
6	Yukon	Transformer	AP	$2.0	$1.5	$0.1	$0.5	$0.3	($0.2)	($0.2)	$0.3	$0.8	750	180
7	AEP-DOM	Interface	500	($1.8)	($2.6)	$0.0	$0.8	($0.1)	($0.0)	$0.0	($0.0)	$0.7	3,572	370
8	Crete - St Johns Tap	Flowgate	MISO	$2.2	$2.9	$0.1	($0.7)	$0.1	$0.0	($0.0)	$0.1	($0.6)	6,708	2,230
9	5004/5005 Interface	Interface	500	($7.7)	($9.4)	($0.1)	$1.6	($0.6)	$0.5	$0.1	($1.0)	$0.6	1,810	940
10	Bedington - Black Oak	Interface	500	($2.2)	($2.7)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.6	1,358	14
11	Beaver - Sammis	Line	DLCO	($0.6)	($1.4)	($0.0)	$0.7	($0.1)	$0.1	$0.0	($0.2)	$0.5	442	22
12	Arsenal - Highland	Line	DLCO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.3)	$0.0	$0.4	$0.5	168	30
13	West	Interface	500	($6.8)	($7.2)	($0.1)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	1,734	40
14	Burnham - Munster	Flowgate	MISO	$0.9	$1.2	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
15	East Frankfort - Crete	Line	ComEd	$0.8	$1.2	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	3,092	658
18	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	100	18
20	Clinton - Findlay	Line	DLCO	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.2	48	24
23	St. Joe	Other	DLCO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	878	0
24	Beaver - Clinton	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
33	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0

Table G-40 DLCO Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$12.2	($0.0)	$0.2	$12.4	$0.2	($0.5)	($0.3)	$0.4	$12.8	1,260	282
2	AP South	Interface	500	($36.5)	($43.0)	($0.2)	$6.4	($2.3)	($0.5)	$0.2	($1.5)	$4.8	7,080	2,502
3	Collier - Elwyn	Line	DLCO	$4.5	$0.3	$0.1	$4.4	($0.0)	($0.1)	($0.0)	$0.0	$4.4	920	222
4	Carson - Oakland	Line	DLCO	$2.6	$0.0	$0.0	$2.6	($0.0)	($0.0)	$0.0	($0.0)	$2.6	350	2
5	Bedington - Black Oak	Interface	500	($11.6)	($13.3)	($0.1)	$1.7	($0.2)	($0.0)	$0.0	($0.2)	$1.5	3,704	222
6	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	942	178
7	Sammis - Wylie Ridge	Line	ATSI	($1.8)	($3.2)	($0.0)	$1.4	($0.1)	$0.2	$0.0	($0.2)	$1.2	1,042	120
8	Elrama - Mitchell	Line	AP	($2.5)	($1.9)	($0.1)	($0.7)	($0.1)	$0.0	$0.1	($0.0)	($0.7)	934	484
9	East Frankfort - Crete	Line	ComEd	$1.5	$2.3	($0.0)	($0.8)	$0.1	($0.1)	($0.0)	$0.2	($0.6)	5,584	1,700
10	5004/5005 Interface	Interface	500	($10.9)	($12.7)	($0.1)	$1.7	($1.3)	($0.1)	$0.1	($1.1)	$0.6	2,758	1,142
11	Cloverdale - Lexington	Line	500	($1.4)	($2.1)	$0.0	$0.7	($0.2)	($0.0)	($0.0)	($0.2)	$0.5	2,138	1,356
12	Arsenal - Highland	Line	DLCO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	96	14
13	Arsenal - Oakland	Line	DLCO	$0.1	($0.1)	$0.0	$0.3	($0.3)	$0.3	($0.0)	($0.6)	($0.4)	178	108
14	Collier	Transformer	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	16	16
15	Beaver - Mansfield	Line	DLCO	($0.1)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	342	0
23	Crescent - Sewickly	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
25	Cheswick - Logan's Ferry	Line	DLCO	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	70	0
27	Beaver	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.0)	($0.1)	($0.1)	0	14
30	Arsenal	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	16	0
34	Collier - Woodville	Line	DLCO	$0.1	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	40	6

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table G-41 Dominion Control Zone top congestion cost impacts (By facility): Calendar Year 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$313.4	$233.9	$3.4	$82.9	($0.3)	$0.6	($4.1)	($5.0)	$77.9	8,222	2,026
2	Clover	Transformer	Dominion	$23.2	$7.9	$4.4	$19.8	($0.5)	$2.7	($8.2)	($11.4)	$8.4	2,476	938
3	AEP-DOM	Interface	500	$51.0	$46.9	$1.4	$5.6	($0.3)	($0.6)	($0.4)	($0.1)	$5.5	3,572	370
4	Danville - East Danville	Line	AEP	$60.1	$55.4	$0.7	$5.4	$0.0	$0.0	$0.0	$0.0	$5.4	9,216	0
5	Bedington - Black Oak	Interface	500	$32.0	$28.6	$0.6	$4.0	$0.0	($0.0)	($0.1)	$0.0	$4.0	1,358	14
6	Valley	Transformer	Dominion	$24.7	$20.0	$1.1	$5.8	($1.3)	($0.1)	($1.3)	($2.5)	$3.3	438	196
7	Chaparral - Carson	Line	Dominion	$5.1	$4.4	$0.5	$1.2	$0.2	$1.6	($3.0)	($4.5)	($3.3)	392	360
8	Dickerson - Quince Orchard	Line	Pepco	($32.1)	($29.0)	($0.9)	($4.1)	$0.4	$1.1	$1.5	$0.8	($3.3)	284	152
9	Graceton - Raphael Road	Line	BGE	$19.1	$16.5	$0.5	$3.1	($0.2)	($0.6)	($0.6)	($0.2)	$2.9	2,314	830
10	Crete - St Johns Tap	Flowgate	MISO	$25.7	$22.9	$0.1	$2.9	($0.3)	($0.4)	($0.2)	($0.0)	$2.9	6,708	2,230
11	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($1.0)	($1.6)	($3.4)	($2.9)	($2.9)	0	218
12	Cloverdale - Lexington	Line	500	$12.0	$8.7	$0.9	$4.2	($0.3)	($0.6)	($2.1)	($1.7)	$2.5	1,204	854
13	Cranes Corner - Fredericksburg	Line	Dominion	($3.3)	($6.0)	($0.2)	$2.5	$0.2	$0.4	$0.2	($0.0)	$2.5	250	46
14	Wylie Ridge	Transformer	AP	$19.6	$17.6	$0.8	$2.8	$0.1	($0.1)	($0.6)	($0.3)	$2.5	3,836	760
15	Hopewell - Chesterfield	Line	Dominion	$7.8	$4.6	$0.3	$3.5	($0.3)	($1.2)	($2.0)	($1.2)	$2.3	308	126
17	Halifax - Mount Laurel	Line	Dominion	$4.7	$1.8	$0.2	$3.1	($0.4)	$0.3	($0.2)	($0.9)	$2.3	1,456	294
19	Dooms	Transformer	Dominion	$18.2	$13.6	$1.1	$5.7	($5.0)	($1.1)	($3.7)	($7.6)	($1.9)	298	236
22	Bristers - Ox	Line	Dominion	($1.7)	($3.1)	$0.0	$1.5	$0.4	$0.5	($0.1)	($0.1)	$1.4	66	50
23	Powhatan - Bremo	Line	Dominion	$2.4	$1.3	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	60	0
28	Crozet - Dooms	Line	Dominion	$3.2	$2.6	$0.2	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	236	4

Table G-42 Dominion Control Zone top congestion cost impacts (By facility): Calendar Year 2010

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$67.8	($42.5)	$0.8	$111.0	$2.7	$4.7	($0.6)	($2.5)	$108.5	7,080	2,502
2	Doubs	Transformer	AP	$0.1	($11.5)	($0.1)	$11.5	$1.5	$0.8	$0.4	$1.1	$12.6	2,492	896
3	Cloverdale - Lexington	Line	500	$17.5	$5.1	$2.0	$14.5	($1.8)	($2.5)	($2.7)	($2.0)	$12.5	2,138	1,356
4	Bedington - Black Oak	Interface	500	$20.8	$14.0	$3.0	$9.9	($0.2)	($0.1)	($0.9)	($1.0)	$8.8	3,704	222
5	Clover	Transformer	Dominion	$6.0	($2.6)	$1.6	$10.1	($0.3)	$0.3	($1.9)	($2.5)	$7.7	1,004	516
6	Pleasant View	Transformer	Dominion	$0.7	$0.0	$0.0	$0.7	($4.2)	$1.4	($0.6)	($6.2)	($5.5)	84	202
7	Millville - Sleepy Hollow	Line	Dominion	$1.1	($4.3)	($0.2)	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	802	0
8	Millville - Old Chapel	Line	AP	$0.3	($3.0)	($0.4)	$3.0	$0.7	$0.3	$1.3	$1.6	$4.6	420	278
9	Dooms	Transformer	Dominion	$3.3	($0.5)	($0.0)	$3.8	($0.6)	($0.7)	$0.1	$0.2	$4.0	162	62
10	Ox - Francona	Line	Dominion	$3.3	($0.6)	$0.0	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	132	0
11	AEP-DOM	Interface	500	$14.9	$12.1	$0.6	$3.4	($0.1)	($0.3)	($0.1)	$0.1	$3.5	942	178
12	Dickerson - Pleasant View	Line	Pepco	$3.9	$0.6	$0.1	$3.4	($0.1)	($0.3)	($0.2)	$0.0	$3.4	370	194
13	Ox - Glebe	Line	Dominion	$2.5	($0.7)	$0.0	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	60	0
14	East Frankfort - Crete	Line	ComEd	$4.8	$2.1	$0.2	$2.9	($0.2)	($0.5)	($0.2)	$0.1	$2.9	5,584	1,700
15	Chuckatuck - Benns Church	Line	Dominion	$2.5	($0.2)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	152	0
17	Endless Caverns	Transformer	Dominion	$0.8	($1.2)	$0.0	$2.0	($0.0)	($0.0)	$0.0	$0.0	$2.0	1,082	6
20	Greenwich - Elizabeth River	Line	Dominion	$1.6	($0.2)	$0.0	$1.8	$0.1	$0.0	($0.0)	$0.0	$1.8	64	44
21	Pleasant View	Line	Dominion	$1.8	$0.1	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	64	0
22	Yadkin	Transformer	Dominion	$1.5	$0.1	$0.0	$1.5	$0.2	($0.1)	($0.1)	$0.3	$1.7	52	42
23	Danville - East Danville	Line	Dominion	$4.5	$2.7	($0.3)	$1.5	($0.2)	($0.4)	($0.0)	$0.3	$1.7	2,614	280

Marginal Losses

Zonal Marginal Loss Costs

Table G-43 Provides the marginal loss costs by control zone and type for the 2011 calendar year. Table G-44 provides the total marginal loss costs by control zone and month for the 2011 calendar year.

Table G-43 Marginal[4] loss costs by control zone and type (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$32.0	$6.9	$0.7	$25.8	$0.0	($0.6)	($0.5)	$0.1	$0.0	$26.0
AEP	($260.3)	($568.1)	$30.5	$338.3	$10.5	$13.9	($16.2)	($19.7)	$0.0	$318.6
AP	($6.2)	($103.7)	$7.2	$104.7	$3.0	$3.8	($1.9)	($2.7)	$0.0	$102.0
ATSI	($39.7)	($61.0)	$6.9	$28.3	$2.8	$2.4	($9.3)	($9.0)	$0.0	$19.3
BGE	$111.6	$54.2	$6.2	$63.5	$1.6	($1.0)	($4.9)	($2.3)	$0.0	$61.3
ComEd	($578.8)	($816.7)	$9.8	$247.7	$23.0	$9.3	($2.2)	$11.6	$0.0	$259.2
DAY	($18.0)	($84.3)	$6.1	$72.3	$0.5	$4.4	($2.4)	($6.2)	$0.0	$66.1
DLCO	($21.4)	($38.1)	$1.0	$17.7	($2.1)	$0.3	($0.8)	($3.1)	$0.0	$14.6
Dominion	$112.8	($13.3)	$10.1	$136.2	$6.9	$5.3	($9.1)	($7.5)	$0.0	$128.7
DPL	$68.0	$15.9	$2.0	$54.1	($3.7)	$0.1	($1.8)	($5.6)	$0.0	$48.5
External	($33.5)	($40.0)	($49.9)	($43.4)	($5.9)	($8.2)	$14.2	$16.5	$0.0	($26.9)
JCPL	$69.1	$31.8	$0.9	$38.1	$0.4	($0.4)	($1.1)	($0.3)	$0.0	$37.9
Met-Ed	$13.3	($5.2)	$0.0	$18.5	$0.7	($0.1)	($0.2)	$0.6	$0.0	$19.1
PECO	$105.5	$45.3	$0.7	$60.8	($0.8)	$0.2	($0.6)	($1.6)	$0.0	$59.2
PENELEC	($37.8)	($100.5)	($0.6)	$62.1	$2.2	$1.0	$0.2	$1.4	$0.0	$63.5
Pepco	$96.3	$46.5	$4.1	$53.9	($1.4)	($1.0)	($3.1)	($3.4)	$0.0	$50.5
PPL	$32.2	($22.4)	$1.6	$56.2	$3.0	$2.1	($0.3)	$0.7	$0.0	$56.9
PSEG	$136.4	$60.0	$16.3	$92.7	$0.4	$9.1	($12.2)	($20.9)	$0.0	$71.8
RECO	$3.3	$0.5	$0.1	$3.0	($0.0)	($0.4)	($0.1)	$0.3	$0.0	$3.2
Total	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.3	$40.2	($52.2)	($51.0)	$0.0	$1,379.5

4 The "External" zone was labeled as "PJM" in previous State of the Market reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM external interfaces.

Table G-44 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2011

	Marginal Loss Costs by Control Zone (Millions)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$6.0	$3.2	$1.9	$0.8	$0.8	$0.3	$0.0	$26.0
AEP	$42.3	$25.8	$24.0	$19.4	$18.3	$30.6	$54.9	$34.5	$24.6	$15.4	$15.9	$12.9	$0.0	$318.6
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$16.1	$10.1	$7.4	$5.3	$5.3	$5.3	$0.0	$102.0
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$1.5	$2.7	$2.2	$1.7	$5.2	$2.8	$3.2	$0.0	$19.3
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$11.7	$6.6	$4.8	$3.3	$3.5	$2.9	$0.0	$61.3
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$30.1	$21.0	$21.1	$18.0	$18.6	$17.3	$0.0	$259.2
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$10.3	$7.0	$6.7	$5.6	$4.8	$4.2	$0.0	$66.1
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$1.3	$1.1	$1.2	$1.3	$1.1	$0.9	$0.0	$14.6
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.3	$24.0	$14.6	$10.2	$6.5	$6.0	$5.5	$0.0	$128.7
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$7.9	$5.5	$3.8	$1.9	$1.7	$1.0	$0.0	$48.5
External	$6.4	$4.1	$0.0	($0.7)	($0.1)	($2.5)	($6.9)	($7.2)	($7.4)	($3.6)	($6.5)	($2.6)	$0.0	($26.9)
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$6.6	$3.3	$2.7	$1.4	$0.7	$1.3	$0.0	$37.9
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$2.4	$1.8	$1.4	$1.4	$1.5	$1.6	$0.0	$19.1
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$10.0	$5.7	$3.7	$3.8	$3.7	$3.9	$0.0	$59.2
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$10.3	$7.2	$4.7	$3.4	$3.2	$1.9	$0.0	$63.5
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$8.2	$5.2	$4.1	$2.8	$2.5	$2.3	$0.0	$50.5
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$7.9	$6.1	$3.9	$4.2	$4.4	$4.0	$0.0	$56.9
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$9.7	$6.2	$6.0	$5.5	$4.0	$4.5	$0.0	$71.8
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$0.5	$0.3	$0.3	$0.2	$0.1	$0.1	$0.0	$3.2
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$213.7	$134.5	$102.9	$82.0	$74.3	$70.6	$0.0	$1,379.5

FTR Volumes

Introduction

This Appendix presents the data used to create Figure 12-3 in the *2011 State of the Market Report for PJM*. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the buy, sell and self-scheduled offers that cleared. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Long Term and Annual Auction volume is included in June of each planning period.

Table H-1 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003 to 2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table H-2 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004 to 2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table H-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005 to 2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table H-4 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006 to 2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table H-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007 to 2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table H-6 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008 to 2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table H-7 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009 to 2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table H-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010 to 2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table H-9 Long Term, Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011 to 2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Total	13,524,022	1,751,509	18,023,854

Glossary

Aggregate
Combination of buses or bus prices.

Ancillary Services
Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)
Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

Associated unit (AU)
A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.

Auction Revenue Right (ARR)
A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.

Automatic Generation Control (AGC)
An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.

Average hourly LMP
An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.

Avoidable cost rate (ACR)
The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)
A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market
Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)
Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Bilateral agreement
An agreement between two parties for the sale and delivery of a service.

Black Start Unit
A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.

Bottled generation
Economic generation that cannot be dispatched because of local operating constraints.

Burner tip fuel price
The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.

Bus
An interconnection point.

Capacity deficiency rate (CDR)

The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.

Capacity Emergency Transfer Limit (CETL)

The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity queue

A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)

An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)

A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)

A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

Control Zone

An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement Bids (DEC)

An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations

Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports .

Demand Resource

A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate

The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

Disturbance Control Standard

A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)

Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.

Eastern Region

Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

Economic generation

Units producing energy at an offer price less than or equal to LMP.

End-use customer
Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)
The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)
A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)
The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)
The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)
The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource
A generation resource located outside metered boundaries of the PJM RTO.

Financial Transmission Right (FTR)
A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm Point-to-Point Transmission Service
Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service
Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid
Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)
An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate
A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

Frequently mitigated unit (FMU)
A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Generation Control Area (GCA) and Load Control Area (LCA)
Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations
Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.

Generation Offers
Schedules of MW offered and the corresponding offer price.

Generation owner
A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross export volume (energy)

The sum of all export transaction volume (MWh).

Gross import volume (energy)

The sum of all import transaction volume (MWh).

Gigawatt (GW)

A unit of power equal to 1,000 megawatts.

Gigawatt-day

One GW of energy flow or capacity for one day.

Gigawatt-hour (GWh)

One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)

HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)

Electricity system frequency is measured in hertz.

HRSG

Heat recovery steam generator. An air-to-steam heat exchanger.

Increment offers (INC)

Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction

Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Inframarginal unit

A unit that is operating, with an accepted offer that is less than the clearing price.

Installed capacity

Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

Load

Demand for electricity at a given time.

Load Management

Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load-serving entity (LSE)

Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.

Locational Deliverability Area (LDA)

Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit

The last, highest cost, generation unit to supply power under a merit order dispatch system.

Market-clearing price

The price that is paid by all load and paid to all suppliers.

Market participant

A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.

Market user interface
A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.

Maximum daily starts
The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts
The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

Mean
The arithmetic average.

Median
The midpoint of data values. Half the values are above and half below the median.

Megawatt (MW)
A unit of power equal to 1,000 kilowatts.

Megawatt-day
One MW of energy flow or capacity for one day.

Megawatt-hour (MWh)
One MWh is a megawatt produced or consumed for one hour.

Megawatt-year
One MW of energy flow or capacity for one calendar year.

Minimum down time
The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.

Minimum run time
The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

Monthly CCM
The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).

Multimonthly CCM
The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)
The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.

Net exchange (capacity)
Capacity imports less exports.

Net interchange (energy)
Gross import volume less gross export volume in MWh.

Network Transmission Service
Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation
Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service
Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

North American Electric Reliability Council (NERC)
A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Off peak
For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.

On peak
For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Opportunity cost
In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule
A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

PJM member
Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.

PJM planning year
The calendar period from June 1 through May 31.

Point of Receipt (POR) and Point of Delivery (POD)
Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource
A generating resource that the seller has turned over to PJM for scheduling and control.

Price duration curve
A graphic representation of the percent of hours that a system's price was at or below a given level during the year.

Price-sensitive bid
Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.

Primary operating interfaces
Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.

Ramp-limited desired (MW)
The achievable MW based on the UDS requested ramp rate.

Regional Transmission Expansion Planning (RTEP)
ProtocolThe process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation
Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).

Reliability Pricing Model (RPM)
PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Selective catalytic reduction (SCR)
NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

Shadow price

The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.

Short-Term Resource Procurement Target

The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.

Sources and sinks

Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

Spot market

Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator

A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

Synchronized reserve

Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.

System installed capacity

System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.

System lambda

The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)

A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and *RH* is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: WWP = Td - (0.5 * (WIND -10)) if WIND > 10 mph; WWP = Td if WIND <= 10 mph (where Td is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

List of Acronyms

AC2	Advanced Control Center
ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMI	Advanced Metering Infrastructure
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BOR	Balancing Operating Reserve
BRA	Base Residual Auction
BSSWG	Black Start Services Working Group
BTU	British thermal unit
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDS	Cost Development Subcommittee
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIDS	Critical Infrastructure Protocol
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator

CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPA	Environmental Protection Agency
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic Precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FSL	Firm Service Load
FTR	Financial Transmission Right
FTRTF	Financial Transmission Rights Task Force

GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
ITSCED	Intermediate Term Security Constrained Economic Dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MCP	Market-clearing price

MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company

PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area

PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPb	
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCP	Regulation market-clearing price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCED	Security Constrained Economic Dispatch
SCPA	South central Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	SERC Reliability Corporation
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative

SMP	System marginal price
SNCR	Selective Non-Catalytic Reduction
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds
VOM expense	Variable operation and maintenance
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages