Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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2013

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 *2013 Quarterly State of the Market Report for PJM: January through March*.

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

2013 Q1 In Review

The state of the PJM markets in the first three months of 2013 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 the first three months of 2013. 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. The significant changes in the economic environment of PJM markets in 2011 and 2012 continued in the first quarter of 2013.

Continued success requires that market participants have access to all the information about the economic fundamentals of PJM markets necessary to make rational decisions. There are still areas where more transparency is required in order to permit markets to function effectively. The provision of clear, understandable information about market fundamentals matters.

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.

The market dynamics changed in the first quarter of 2013. A combination of increased, weather related, demand, and higher fuel costs led to a reversal of the downward trend in LMP. PJM LMPs were substantially higher than in the first quarter of 2012. The load-weighted average LMP was $37.41 per MWh, 19.9 percent higher in the first quarter of 2013 than in the first quarter of 2012.

The price of natural gas, especially in the eastern part of PJM, increased in the first three months of 2013, and coal prices were mixed in the first three months of 2013 compared to the first three months of 2012.

As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units, coal output increased in the first quarter and gas output decreased in the first quarter, also reversing the trend towards reduced coal output.

The results of the energy market dynamics in the first quarter of 2013 were generally positive for new coal units. In a continuation from the fourth quarter of 2012, new coal units ran at a lower fuel-only marginal cost than new combined cycle units. The combination of higher energy prices and gas prices increasing relative to coal prices resulted in significantly higher energy market net revenues for the new entrant coal plant in the first three months of 2013. In the first three months of 2013, energy market net revenues for a coal plant in seven zones exceeded fifty percent of the 2012 annual energy market net revenues.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need better information about unit retirements in order to permit new entrants to address reliability issues. For example, the markets need better information about the reasons for operating reserve charges in order to permit market responses to persistent high payments of operating reserve credits. Data on the units receiving operating reserve credits and the reasons for those credits should be made publicly available to permit better understanding of operating reserve levels and to facilitate competition for providing the same services.

The market design should permit market prices to reflect underlying supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed, including better LDA definitions, the effectiveness of the transmission interconnection queue process, 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.

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 will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics

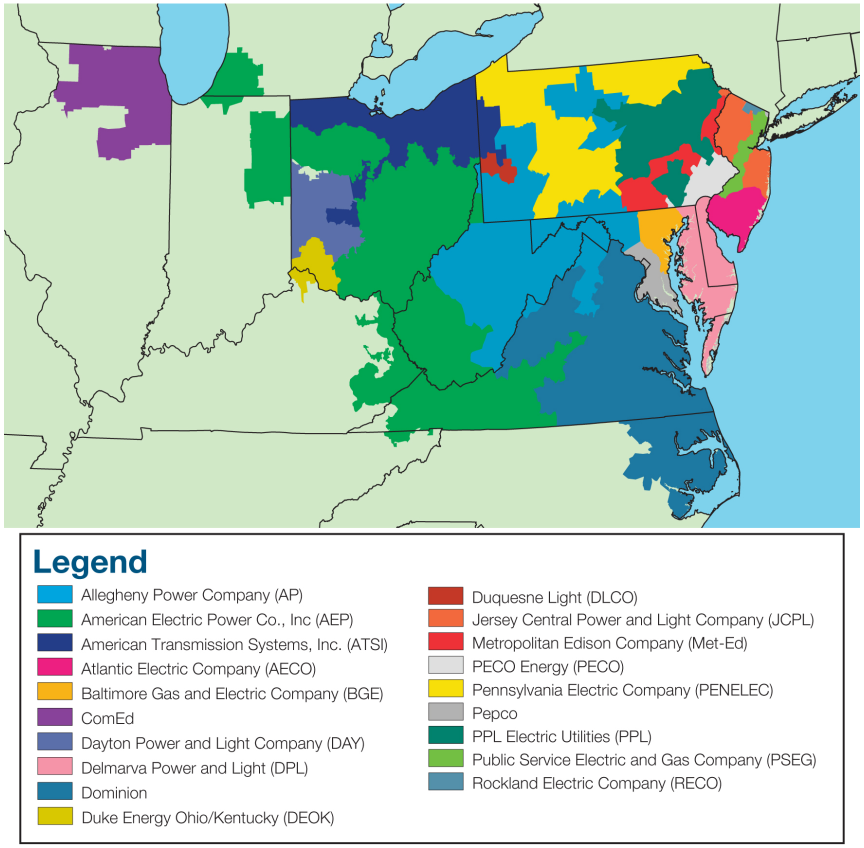
	Period
Energy	**Jan - Mar 2013**
Load	197,288 GWh
Generation	202,674 GWh
Imports (+) / Exports (-)	1,098 GWh
Peak	**Jan 22, 2013 19:00**
Peak Load	126,632 MW
Load Factor	0.721
Installed Capacity	**As of 3/31/2013**
Installed Capacity	181,896 MW
Ancillary Services	**Jan - Mar 2013**
Regulation Requirement *	828 MW
RTO Primary Reserve Requirement	2,063 MW
Total Billing	**Jan - Mar 2013**
Total Billing	$7.762 Billion

* Daily average

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2013, had installed generating capacity of 181,896 megawatts (MW) and about 820 market buyers, sellers and traders of electricity[1] in a region including more than 60 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 the first three months of 2013, PJM had total billings of $7.76 billion, up from $6.94 billion in the first three months of 2012. As part of the 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 19 control zones



1 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
2 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
3 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2013. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

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 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.[4,5]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2013, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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.

4 See also the *2012 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

5 Analysis of 2013 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. In January 2012, the Duke Energy Ohio/Kentucky 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 2013, see *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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 (TPS) 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.

The MMU concludes the following for the first three months of 2013:

Table 1-2 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 the first three months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 1047 and a maximum of 1409 in the first three months of 2013.
- 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 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 the exercise of 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.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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.[6] 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.[7]

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. 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

6 OATT Attachment M

7 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.

the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[8]

- 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 have failed the TPS test, which is conducted at the time of the auction.[9]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, 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 the definition of DR which permits inferior products to substitute for capacity.

Table 1-4 The Regulation Market results were indeterminate for January through March, 2013

	January through March 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the first three months of 2013 because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 87 percent of the hours in January through March, 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through March, 2013 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 indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance.
- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

8 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
9 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.

Table 1-5 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. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 6.3 percent of the hours in January through March, 2013.
- 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 competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-6 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 market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 12 percent of offers reflected economic withholding.
- 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 1-7 The FTR Auction Markets results were competitive

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

- 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.
- 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 mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[10] 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.[11]

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.

The MMU's quarterly state of the market reports supplement the annual state of the market report for the prior year, and extend the analysis into the current year. Readers of the quarterly state of the market reports should refer to the prior annual report for detailed explanation of reported metrics and market design.

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.[12] The MMU has direct, confidential access to the FERC.[13] The MMU may also refer matters to the attention of State commissions.[14]

The MMU monitors market behavior for violations of FERC Market Rules.[15] 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,[16] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[17] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[18]

10 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).

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

12 OATT Attachment M § IV.

13 OATT Attachment M § IV.K.3.

14 OATT Attachment M § IV.H.

15 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.").

16 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.

17 OATT Attachment M § II(h-1).

18 OATT Attachment M § IV.C.

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[19] 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[20] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[21] 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).[22] 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.[23]

The MMU also reviews operational parameter limits included with unit offers,[24] evaluates compliance with the requirement to offer into the energy and capacity markets,[25] evaluates the economic basis for unit retirement requests[26] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[27]

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.[28] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[29] 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.[30] 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.[31] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[32]

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily

19 OATT Attachment M § IV.I.1.
20 *Id.*
21 *Id.*
22 See OATT Attachment M–Appendix § II.A.
23 OATT Attachment M–Appendix § II.E.
24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.D.
29 *Id.*
30 *Id.*
31 *Id.*
32 OATT Attachment M § VI.A.

mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

Table 1-8 Prioritized summary of new recommendations

Priority	Section	Description
Low	2 - Energy Market	Load at generation pnodes should be treated as load, rather than negative generation.
Low	2 - Energy Market	Hub definition and change procedures should be published in a PJM manual.
High	3 - Operating Reserve	Operating reserve confidentiality rules should be revised for more transparency.
High	9 - Ancillary Services	Black start confidentiality rules should be revised for more transparency.

Detailed 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,"[33] 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. In this *2013 Quarterly State of the Market report for PJM: January through March*, the MMU makes the following new recommendations.

From Section 2, "Energy Market":

- The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.
- The MMU recommends that PJM include in a manual the process of initially defining hubs and then approving additions, deletions and changes to hub definitions. (New Recommendation)

From Section 3, "Operating Reserve":

- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow a more transparent disclosure of information regarding the reasons for operating reserves in specific locations of the PJM region. This would include the publication of operating reserve information by unit.

From Section 4, "Capacity":

- There are no new recommendations in Section 4.

From Section 5, "Demand Response":

- There are no new recommendations in Section 5.

From Section 6, "Net Revenue":

- There are no new recommendations in Section 6.

From Section 7, "Environmental and Renewables":

- There are no new recommendations in Section 7.

From Section 8, "Interchange Transactions":

- There are no new recommendations in Section 8.

From Section 9, "Ancillary Services":

- The MMU recommends that PJM revise the current confidentiality rules in order to allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

33 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

From Section 10, "Congestion and Marginal Losses":

- There are no new recommendations in Section 10.

From Section 11, "Planning":

- There are no new recommendations in Section 11.

From Section 12, "FTRs and ARRs":

- There are no new recommendations in Section 12.

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 1-9 provides the average price and total revenues paid, by component, for the first three months of 2012 and 2013.

Table 1-9 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.7 percent of the total price per MWh in the first three months of 2013.

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.[34]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[35]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[36]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[37]
- 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.[38]
- 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.[39]
- 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.[40]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[41]

34 OATT §§ 13.7, 14.5, 27A & 34.
35 OA Schedules 1 §§ 3.2.3 & 3.3.3.
36 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
37 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
38 OATT Schedule 12.
39 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
40 OATT Schedule 1A.
41 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

- The Black Start component is the average cost per MWh of black start service.[42]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[43]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[44]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[45]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[46]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[47]

42 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.
43 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
44 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
45 OA Schedule 1 § 3.6.
46 OA Schedule 1 § 5.3b.
47 OA Schedule 1 § 3.2.3A.001.

Table 1-9 Total price per MWh by category and total revenues by category: January through March, 2012 and 2013

Category	Jan-Mar 2012 $/MWh	Jan-Mar 2013 $/MWh	Percent Change Totals	Jan-Mar 2012 Percent of Total	Jan-Mar 2013 Percent of Total
Load Weighted Energy	$31.21	$37.41	19.9%	68.6%	74.9%
Capacity	$7.51	$4.83	(35.7%)	16.5%	9.7%
Transmission Service Charges	$4.80	$4.69	(2.4%)	10.6%	9.4%
Operating Reserves (Uplift)	$0.49	$0.94	90.2%	1.1%	1.9%
Reactive	$0.48	$0.63	30.7%	1.1%	1.3%
PJM Administrative Fees	$0.36	$0.44	20.6%	0.8%	0.9%
Transmission Enhancement Cost Recovery	$0.28	$0.40	46.2%	0.6%	0.8%
Regulation	$0.17	$0.28	60.9%	0.4%	0.6%
Black Start	$0.02	$0.14	524.6%	0.0%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(3.4%)	0.2%	0.2%
Synchronized Reserves	$0.03	$0.04	45.1%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	3.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(0.5%)	0.0%	0.0%
Load Response	$0.01	$0.01	(17.8%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00			0.0%
Transmission Facility Charges	$0.00	$0.00	(6.4%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	2,106.1%	0.0%	0.0%
Total	$45.48	$49.92	9.8%	100.0%	100.0%

Section Overviews

Overview: Section 2, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 4,230, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[48] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first three months of 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three

48 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.

months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2013.[49]

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segmen t, 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 the first three months of 2013. PJM offer caps units 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 first three months of 2013, offer capping levels increased as a result of the inclusion of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in the first three months of 2012 to 4.1 percent in the first three months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.9 percent in the first three months of 2012 to 3.6 percent in the first three months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 48 units eligible for FMU or AU status in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

  The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- **Local Market Structure.** In the first three months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 25 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.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

  In the first three months of 2013, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$2.69 per MWh. The adjusted markup was less negative, -$0.95 per MWh or -2.5 percent of the PJM real-time, load-weighted average LMP of $37.41 per MWh.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs.

49 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

  PJM average day-ahead load in the first three months of 2013, including DECs and up-to congestion transactions, increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW. The day-ahead load growth was 91.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

  PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW. The day-ahead generation growth was 109.4 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

  The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.

- **Generation Fuel Mix.** During the first three months of 2013, coal units provided 44.5 percent, nuclear units 35.5 percent and gas units 15.1 percent of total generation. Compared to the first three months of 2012, generation from coal units increased 16.2 percent, generation from nuclear units increased 2.0 percent, and generation from gas units decreased 17.2 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

- **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 increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[50]

  There is currently no documentation addressing how hubs are defined and changed in the tariff or manuals. The MMU recommends that PJM include in the appropriate manual the process of initially defining hubs and the the process for approving additions, deletions and changes to hub definitions. According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

- **Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot

50 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points. For the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based shortage events in the first three months of 2013.

Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 4,230 MW in the first three months of 2013 compared to the first three months of 2012, while peak load increased by 4,093 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 129,258 MW to 143,585 MW, or 11.1 percent. In the Real-Time Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 86,329 MW to 91,337 MW, or 5.8 percent. 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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first three months of 2013 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.[51] 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

51 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

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. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2013.

Overview: Section 3, "Operating Reserve"

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 111.8 percent in the first three months of 2013 compared to the first three months of 2012, to a total of $260.2 million.Total operating reserve charges in the first three months of 2013 were $260.2 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 9.0 percent, the balancing operating reserve charges proportion was 61.1 percent, the reactive services charges proportion was 21.4 percent, the synchronous condensing charges proportion was 0.001 percent and the black start services charges proportion was 8.5 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.082 per MWh, the day-ahead operating reserve rate including unallocated congestion charges averaged $0.114 per MWh, the balancing operating reserve reliability rates averaged $0.058, $0.065 and $0.003 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $1.001, $5.967 and $0.055 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $0.655 per MWh and canceled resources rate averaged $0.0002 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 52.6 percent of all day-ahead generator credits and 69.2 percent of all balancing generator credits. Combustion turbines and diesels received 77.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 88.7 percent of all reactive services credits.
- **Economic – Noneconomic Generation.** In the first three months of 2013, 82.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.3 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first three months of 2013, 79.7 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.3 percent by transactions at hubs and 14.0 percent by transactions at interfaces.
- Generators in the Eastern Region paid 17.4 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 87.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 14.7 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 12.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators paid 13.7 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.99 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 48.6 percent of all credits. The top 10 organizations received 90.8 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 5372, balancing operating reserves was 5291 and lost opportunity cost HHI was 5418.
- **Day-Ahead Unit Commitment for Reliability:** In the first three months of 2013, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, of which, 67.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first three months of 2013, lost opportunity cost credits decreased by $1.2 million compared to the first three months of 2012. In the first three months of 2013, the top three control zones receiving lost opportunity cost credits, ATSI, AP and ComEd combined for 70.3 percent of all lost opportunity cost credits, 54.0 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 73.4 percent of all day-ahead generation not called in real time by PJM from those unit types and 82.0 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In the first three months of 2013, lost opportunity cost credits would have been reduced by $6.7 million, or 34.0 percent, if all changes proposed by the MMU had been implemented.
- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running even if not economic. In the first three months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $22.2 million.
- **Con Edison – PSEG Wheeling Contracts Support:** 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.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in the first three months of 2013, the RTO deviation rate would have been reduced by 74.7 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

Section 3 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 goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

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, the details of the rules which define payments 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, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[52] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

Overall, the MMU recommends that the goal be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

52 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement" for PJM's MRC April 25, 2013 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

Overview: Section 4, "Capacity Market"

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.[53]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future.[54] Effective with the 2012/2013 Delivery Year, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[55] 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.[56]

RPM prices are locational and may vary depending on transmission constraints.[57] 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.

53 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2012 State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
54 See 126 FERC ¶ 61,275 (2009) at P 86.
55 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
56 See 126 FERC ¶ 61,275 (2009) at P 88.
57 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Market Structure

- **PJM Installed Capacity.** During the period January 1, through March 31, 2013, PJM installed capacity decreased 115.1 MW or 0.1 percent from 182,011.1 MW on January 1 to 181,896.0 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2013, 41.8 percent was coal; 28.6 percent was gas; 18.2 percent was nuclear; 6.2 percent was oil; 4.3 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.
- **Market Concentration.** In the 2013/2014 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. 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.[58,59,60]
- **Imports and Exports.** Of the 44.7 MW of imports in the 2013/2014 RPM Third Incremental Auction, all 44.7 MW cleared. Of the cleared imports, 14.5 MW (32.4 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,583.4 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (1,100.4 MW).

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).

Market Conduct

- **2013/2014 RPM Third Incremental Auction.** Of the 410 generation resources which submitted offers, unit-specific offer caps were calculated for zero generation resources (0.0 percent). The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2013/2014 RPM Third Incremental Auction was conducted in the first quarter of 2013. In the 2013/2014 RPM Third Incremental Auction, the RTO clearing price was $4.05 per MW-day.
- 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. The annual weighted average capacity price then declined to $86.33 per MW-day in 2012 before increasing again to $148.33 per MW-day in 2015.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd for January through March is 8.3 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[61]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through March is 85.6 percent, an increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **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 the first three months of 2013, 25.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Section 4 Conclusion

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first three months of 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first three months of 2013.[62]

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[63,64,65,66]

Overview: Section 5, "Demand Response"

- **Demand-Side Response Activity.** In the first three months of 2013, total load reduction under the Economic Load Response Program increased by 12,936 MWh compared to the same period in 2012, from 1,030 MWh in

61 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 or the three months ending March 31, as downloaded from the PJM GADS database on May 2, 2013. 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.

62 For more complete conclusions, see *2012 State of the Market Report for PJM*, Section 4, "Capacity Market."

63 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).

64 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)

65 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).

66 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).

the first three months of 2012 to 13,966 MWh in the first three months of 2013, a 1,256 percent increase. Total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013, a 2,170 percent increase.

Settled reductions and credits were greater in the first three months of 2013 compared to 2012. Participation levels increased following the implementation of Order No. 745, on April 1, 2012, allowing payment of full LMP for demand resources.

Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In the first three months of 2013, Load Management (LM) Program revenues revenue decreased $38.4 million, or 36.8 percent, from $104 million to $66 million. Through the first three months of 2013, Synchronized Reserve credits for demand side resources decreased by $0.6 million compared to the same period in 2012, from $1.3 million to $0.7 million in 2013.

Section 5 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.

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 are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[67]

Overview: Section 6, "Net Revenue"

Net Revenue

- In the first three months of 2013, energy market net revenues for a coal plant in seven zones exceeded fifty percent of the 2012 annual energy market net revenues. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.

Section 6 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

67 For additional conclusions see the *2012 State of the Market Report for PJM*, Section 5, "Demand Response."

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.

Overview: Section 7, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[68] 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

68 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

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 utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility 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.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[69] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.
- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[70] 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. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.
- **Greenhouse Gas Emissions Rule.** On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[71]

69 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

70 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708 (January 14, 2013).

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey 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 such high energy demand days. New Jersey's HEDD rule,[72] 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.[73]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were \$2.80 per ton, above the price floor for 2013.

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. On March 31, 2013, 68.4 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 97.6 percent of coal steam MW had some type of particulate control. NO_x emission controlling technology is used

71 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

72 N.J.A.C. § 7:27–19.

73 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).

by nearly all fossil fuel unit types, and 91.0 percent of fossil fuel fired capacity in PJM has NO_x emission control technology in place.

State 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 March 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 2.0 percent of all load served in Ohio, to 10.7 percent of all load served in Maryland. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

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 which is greater than the marginal cost of producing 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 marginal cost of producing minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 7 Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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 formally recognized as part of 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 incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 8, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[74] During the first three months of 2013, the real-time net interchange of 1,640.5 GWh was greater than net interchange of 800.7 GWh in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than net interchange of -3,224.6 GWh during the first three months of 2012.

  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 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross import in the Real-Time Energy Market (408.9 percent during the first three months of

74 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of the gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[75]
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in only 42.6 percent of hours in the first three months of 2013.
- **PJM and New York ISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[76] The average hourly flow during the first three months of 2013 was -350 MW.[77] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[78] The average hourly flow during the first three months of 2013 was -188 MW.[79] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013.
- **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 and NYISO. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 2013.

75 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

76 In the first three months of 2013, there were 92 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

77 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

78 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

79 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[80] This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.

- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (Figure 8-12).

- **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. 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.[81] These modifications are currently being evaluated by PJM.

- **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. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

Section 8 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 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.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first three months of 2013, including evolving transaction patterns, economics and issues. PJM became a consistent

80 The "Net Scheduled" values shown in Table 8-18 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 Table 8-1 through Table 8-6.

81 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>.

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. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In the first three months of 2013, 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 57.4 percent of the hours for transactions between PJM and MISO and for 43.8 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to 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 relying 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.

On January 15, 2013, PJM and NYISO implemented the market to market provisions of the PJM/NYISO Joint Operating Agreement (JOA). Coordination between NYISO and PJM includes joint redispatch and coordinated operation of the Ramapo PARs located at the NYISO – PJM interface. The goal of this real-time coordination is a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints.[82]

Loop flows remain a significant concern for the efficiency of the PJM market. 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. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[83] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

82 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

83 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Overview: Section 9, "Ancillary Services"

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through March 2013, 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 4.39. This is 33.4 percent increase over January through March 2012 when the ratio was 3.29, was the result of the decrease in demand.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through March, 2013, was 829 MW. This is a 124 MW decrease in the average hourly regulation demand of 953 MW in the same period of 2012.
- **Market Concentration.** In January through March 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1995 (1611 in January through March 2012), which is classified as "highly concentrated."[84] In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (67 percent of hours failed the three pivotal supplier test in January through March 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with costs parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[85] As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through March 2013 was $33.87. This is an increase of $21.26, or 168.6 percent, from the weighted average price for regulation in January through March 2012. The cost of regulation from January through March 2013 was $38.95. This is a $22.19 (132.4 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007 their definition has changed. The RFC Synchronized Reserve Zone has now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[86]

Market Structure

- **Supply.** In January through March, 2013, 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.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, 2012, the requirement remained at 1,300 MW.

84 See the *2012 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.

85 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

86 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 75.

- **Market Concentration.** For January through March, 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4161 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through March, 2012, was 2638, which is classified as "highly concentrated."[87] In January through March, 2013, 35 percent of hours had a maximum market share greater than 40 percent, compared to 43 percent of hours in January through March, 2012.

  In the Mid-Atlantic Subzone, in January through March, 2013, 6.3 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through March, 2012, 49 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through March 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, 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.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $7.35 per MW in January through March, 2013, an increase of $1.29 per MW over January through March, 2012. The total cost of synchronized reserves per MW in January through March 2013 was $12.58, a $4.82 increase from the $7.76 cost of synchronized reserve in January through March 2012. The market clearing price was 58 percent of the total synchronized reserve cost per MW in January through March, 2013, down from 78 percent in January through March, 2012.

- **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 the first quarter of 2013.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[88] 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.[89] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through March, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. 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 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with this direct marginal cost. As of March 31, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into

87 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

88 See 117 FERC ¶ 61,331 (2006).

89 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.

energy within 30 minutes to offer into the DASR Market.[90] Units that do not offer have their offers set to zero.

- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through March, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through March, 2013 was $0.01 per MW. In January through March, 2012, the weighted price of DASR was $0.01 per MW.

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 to automatically remain operating at reduced levels when disconnected from the grid.[91]

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 January through March, 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits of $38,980) to $10.66 per MW in the AEP zone (total credits of $22,352,763).

Section 9 Conclusion

The design of the Regulation Market changed very significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first quarter of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

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 recommends that the rules for compliance be reevaluated.

The MMU concludes that the structure of the DASR Market was competitive in the first three months of 2013, 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.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results

90 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 145.
91 OATT Schedule 1 § 1.3BB.

were competitive in the first three months of 2013. The MMU concludes that the DASR Market results were competitive in the first three months of 2013.

Overview: Section 10, "Congestion and Marginal Losses"

Energy Cost

- **Total Energy Costs.** Total energy costs in the first three months of 2013 decreased by $41.5 million or 30.4 percent from the first three months of 2012, from -$136.4 million to -$177.9 million. Day-ahead net energy costs in the first three months of 2013 decreased by $79.1 million or 69.0 percent from the first three months of 2012, from -$114.6 million to -$193.8 million. Balancing net energy costs in the first three months of 2013 increased by $44.5 million or 155.5 percent from the first three months of 2012, from -$28.6 million to $15.9 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first three months of 2013 increased by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 million. Day-ahead net marginal loss costs in the first three months of 2013 increased by $48.1 million or 19.4 percent from the first three months of 2012, from $248.1 million to $296.2 million. Balancing net marginal loss costs decreased in the first three months of 2013 by $4.8 million or 35.2 percent from the first three months of 2012, from -$13.8 million to -$18.6 million.
- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first three months of 2013 ranged from $86.7 million in February to $101.1 million in January.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments that is paid back in full to load and exports on a load ratio basis.[92] The marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $63.5 million or 51.9 percent, from $122.4 million in the first three months of 2012 to $185.9 million in the first three months of 2013.[93]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $151.0 million or 83.5 percent, from $180.9 million in the first three months of 2012 to $331.9 million in the first three months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $87.5 million or 149.8 percent from -$58.4 million in the first three months of 2012 to -$145.9 million in the first three months of 2013.
- **Monthly Congestion.** Monthly congestion costs in the first three months of 2013 ranged from $48.5 million in March to $77.4 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Readington - Roseland line,

92 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

93 The total zonal congestion numbers were calculated as of April 16, 2013 and are, based on continued PJM billing updates, subject to change.

the Clover and the Cloverdale transformers, and the West Interface. (Table 10-28)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first three months of 2013. Day-ahead congestion frequency increased by 49.1 percent from 54,596 congestion event hours in the first three months of 2012 to 81,378 congestion event hours in the first three months of 2013. Day-ahead, congestion-event hours decreased on the, flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.

- Real-time congestion frequency increased by 45.1 percent from 4,129 congestion event hours in the first three months of 2012 to 5,914 congestion event hours in the first three months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, the transformers, and the transmission lines.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first three months of 2013, for 45.1 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 the first three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.

- **Zonal Congestion.** AP was the most congested zone in the first three months of 2013. AP had -$8.3 million in total load costs, -$44.8 million in total generation credits and -$1.6 million in explicit congestion, resulting in $34.9 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The AP South interface, the Bedington transformer, the Readington – Roseland and the Dickerson - Pleasant View line, and the 5004/5005 Interface contributed $29.0 million, or 83.0 percent of the total AP Control Zone congestion costs.

  The ComED Control Zone was the second most congested zone in PJM in the first three months of 2013, with $34.3 million. The Crete - St Johns Tap flowgate contributed $4.8 million or 13.9 percent of the total ComEd Control Zone congestion cost in first three months of 2013. The AEP Control Zone was the third most congested zone in PJM in the first three months of 2013, with a cost of $25.5 million.

- **Ownership.** In the first three months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first three months of 2013, financial companies received $28.3 million in net congestion credits, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $214.2 million in net congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three months of 2012.

Section 10 Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first three months of 2013 compared to the first three months of 2012. Total marginal loss costs increased in the first three months of 2013 by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the first ten months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 89.9 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period.[94] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 11, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At March 31, 2013, 73,156 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 197,000 MW in the first three months of 2013. Wind projects account for approximately 19,079 MW of nameplate capacity, 26.1 percent of the MW in the queues, and combined-cycle projects account for 42,217 MW, 57.7 percent of the MW in the queues.
- **Generation Retirements.** As shown in Table 11-11, 11,844.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through March 31, 2013, and it is expected that a total of 20,297.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through March 31, 2013, account for 8,453.2 MW, or 39.6 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.2 percent of retirements during this period. Overall, 3,508.1 MW, or 29.6 percent of all MW planned for deactivation from 2013 through 2019, 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, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[95] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built, including 7,584.2 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

94 See the *2012 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

95 OATT Parts IV & VI.

Key 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 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; and Susquehanna – Roseland.

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 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.[96] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Section 11 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

96 *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).

Overview: Section 12, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2012 through March 2013) of the 2012 to 2013 planning period, total participant FTR sell offers were 4,627,336 MW, down from 5,330,537 MW for the same period during the 2011 to 2012 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 (June 2012 through March 2013) planning period increased 11.8 percent from 16,367,977 MW for the same time period of the prior planning period, to 18,299,865 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.0 percent of prevailing flow and 87.9 percent of counter flow FTRs for 2013. Financial entities owned 65.0 percent of all prevailing and counter flow FTRs, including 56.3 percent of all prevailing flow FTRs and 81.5 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first ten months of the 2012 to 2013 planning period were $492,556 (0.06 percent of total FTR target allocations).

- **Credit Issues.** Four participants defaulted during 2013 from eight default events. The average of these defaults was $68,812 with four based on inadequate collateral and four based on nonpayment. The average collateral default was $13,275 and the average nonpayment default was $124,349. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first ten months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,976,401 MW (10.8 percent) of FTR buy bids and 651,226 MW (14.1 percent) of FTR sell offers.

- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 planning period was $0.12, up from $0.10 per MW in the first ten months of the 2011 to 2012 planning period.

- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $21.7 million in net revenue for all FTRs for the first ten months of the 2012 to 2013 planning period, down from $24.8 million for the same time period in the 2011 to 2012 planning period.

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the 2011 to 2012 planning period.[97] FTRs were paid at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $533.2 million of FTR revenues during the first ten months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first ten months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were PSEG and Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both Western Hub.

- **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 $67.4 million in profits for physical entities, of which $63.6 million was from self-scheduled FTRs, and $45.1 million for financial entities. As shown in Table 12-9, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the 2012 to 2013 planning period PJM allocated a total of 14,211.2 MW of residual ARRs with a total target allocation of $4,475,521.

- **ARR Reassignment for Retail Load Switching.** There were 48,077 MW of ARRs associated with approximately $464,100 of revenue that were reassigned in the first ten months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Revenue Adequacy.** For the first ten months of the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $624.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through March 31,

97 Unless specifically noted, payout ratios reported in this section are calculated using PJM's method and are consistent with PJM's reported payout ratios.

2013, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **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 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 89.8 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

Section 12 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 and FTR holders do not have the right to revenue adequacy.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. FTR holders appropriately receive revenues based on actual congestion in both day ahead and real time markets. When day ahead congestion differs significantly from real time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with the differences between modeling in the day ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The payout ratio reported by PJM is understated. The reported payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs. For the 2012 to 2013 planning period, the reported payout ratio is 69.5 percent while the correctly calculated payout ratio is 72.2 percent. The MMU recommends that the calculation of the FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the first ten months of the 2012 to 2013 planning period would have been 85.2 percent instead of the reported 69.5 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the first ten months of the 2012 to 2013 planning period from the reported 69.5 percent to 89.1 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day ahead and balancing congestion. These reasons include the inadequate transmission outage modeling which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day ahead and real time markets, including reactive interfaces; differences in day ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

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 the first three months of 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2013.

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 the first three months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 1047 and a maximum of 1409 in the first three months of 2013.
- 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 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 the exercise of 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.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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

1 Analysis of 2013 market results requires comparison to prior years. In 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. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) 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 *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M

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 4,230, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[4] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first three months of 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2013.[5]
- **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 the first three months of 2013. PJM offer caps units 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 first three months of 2013, offer capping levels increased as a result of the inclusion of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in the first three months of 2012 to 4.1 percent in the first three months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.9 percent in the first three months of 2012 to 3.6 percent in the first three months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 48 units eligible for FMU or AU status in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

  The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- **Local Market Structure.** In the first three months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 25 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.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the

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.

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

In the first three months of 2013, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$2.69 per MWh. The adjusted markup was less negative, -$0.95 per MWh or -2.5 percent of the PJM real-time, load-weighted average LMP of $37.41 per MWh.

The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

  PJM average day-ahead load in the first three months of 2013, including DECs and up-to congestion transactions, increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW. The day-ahead load growth was 91.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

  PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW. The day-ahead generation growth was 109.4 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

  The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.

- **Generation Fuel Mix.** During the first three months of 2013, coal units provided 44.5 percent, nuclear units 35.5 percent and gas units 15.1 percent of total generation. Compared to the first three months of 2012, generation from coal units increased 16.2 percent, generation from nuclear units increased 2.0 percent, and generation from gas units decreased 17.2 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

- **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 increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[6]

There is currently no documentation addressing how hubs are defined and changed in the tariff or manuals. The MMU recommends that PJM include in the appropriate manual the process of initially defining hubs and the the process for approving additions, deletions and changes to hub definitions. According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

- **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. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points. For the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

6 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based shortage events in the first three months of 2013.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 4,230 MW in the first three months of 2013 compared to the first three months of 2012, while peak load increased by 4,093 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 129,258 MW to 143,585 MW, or 11.1 percent. In the Real-Time Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 86,329 MW to 91,337 MW, or 5.8 percent. 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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first three months of 2013 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.[7] 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.

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. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2013.

Market Structure

Supply

Average offered supply increased by 4,230 MW, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[8] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first three months of 2012 and 2013.

8 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.

Figure 2-1 Average PJM aggregate supply curves: January through March of 2012 and 2013

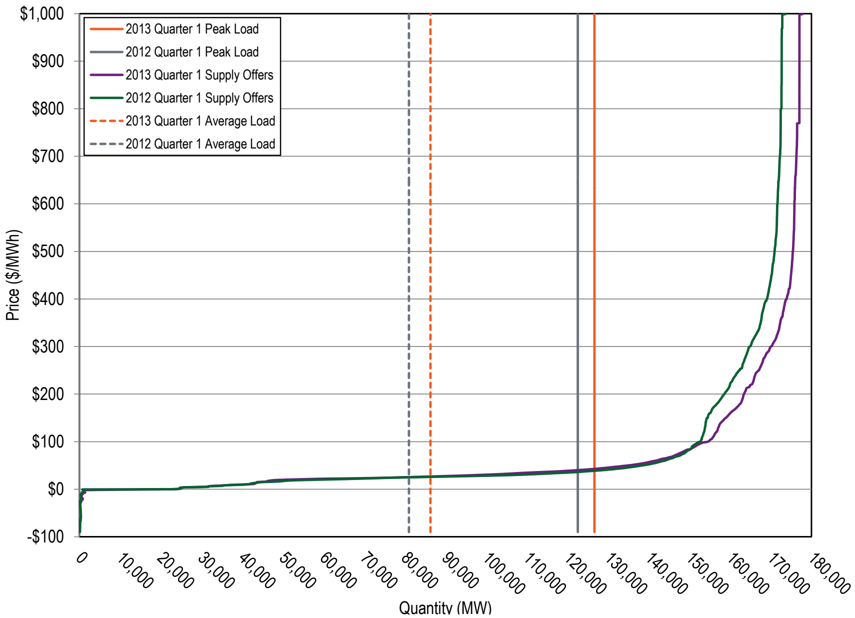


Table 2-2 PJM generation (By fuel source (GWh)): January through March 2012 and 2013[9]

	Jan-Mar 2012		Jan-Mar 2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	77,680.5	39.9%	90,256.4	44.5%	16.2%
Standard Coal	75,124.3	38.6%	87,586.9	43.2%	16.0%
Waste Coal	2,556.2	1.3%	2,669.5	1.3%	0.1%
Nuclear	70,637.4	36.3%	72,028.7	35.5%	2.0%
Gas	36,995.2	19.0%	30,636.8	15.1%	(17.2%)
Natural Gas	36,413.7	18.7%	30,075.7	14.8%	(17.4%)
Landfill Gas	581.3	0.3%	561.1	0.3%	(3.5%)
Biomass Gas	0.1	0.0%	0.0	0.0%	(99.9%)
Hydroelectric	3,357.9	1.7%	3,576.8	1.8%	6.5%
Wind	4,191.6	2.2%	4,788.1	2.4%	14.2%
Waste	1,249.0	0.6%	1,191.0	0.6%	(4.6%)
Solid Waste	979.3	0.5%	951.5	0.5%	(2.8%)
Miscellaneous	269.7	0.1%	239.5	0.1%	(11.2%)
Oil	357.4	0.2%	136.5	0.1%	(61.8%)
Heavy Oil	318.9	0.2%	105.5	0.1%	(66.9%)
Light Oil	37.2	0.0%	23.4	0.0%	(36.9%)
Diesel	1.1	0.0%	0.7	0.0%	(37.9%)
Kerosene	0.2	0.0%	6.9	0.0%	3,764.8%
Jet Oil	0.0	0.0%	0.0	0.0%	116.9%
Solar	43.2	0.0%	59.8	0.0%	38.5%
Battery	0.0	0.0%	0.1	0.0%	271.7%
Total	194,512.3	100.0%	202,674.2	100.0%	4.2%

Energy Production by Fuel Source

Compared to the first three months of 2012, generation from coal units increased 16.2 percent and generation from natural gas units decreased 17.4 percent (Table 2-2). This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

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

Table 2-3 Monthly PJM Generation (By fuel source (GWh)): January through March 2013

	Jan	Feb	Mar	Total
Coal	31,689.2	28,886.8	29,680.4	90,256.4
Standard Coal	30,814.3	28,102.4	28,670.2	87,586.9
Waste Coal	874.9	784.4	1,010.2	2,669.5
Nuclear	25,610.7	22,563.1	23,854.9	72,028.7
Gas	10,261.4	10,319.8	10,055.6	30,636.8
Natural Gas	10,072.4	10,143.6	9,859.7	30,075.7
Landfill Gas	189.0	176.2	195.9	561.1
Biomass Gas	0.0	0.0	0.0	0.0
Hydroelectric	1,234.0	1,127.0	1,215.8	3,576.8
Wind	1,784.4	1,397.5	1,606.2	4,788.1
Waste	414.4	385.2	391.5	1,191.0
Solid Waste	324.8	301.5	325.2	951.5
Miscellaneous	89.6	83.7	66.2	239.5
Oil	62.5	23.8	50.3	136.5
Heavy Oil	55.8	21.9	27.9	105.5
Light Oil	4.2	1.5	17.7	23.4
Diesel	0.6	0.1	0.0	0.7
Kerosene	1.9	0.3	4.7	6.9
Jet Oil	0.0	0.0	0.0	0.0
Solar	15.6	17.6	26.7	59.8
Battery	0.1	0.0	0.0	0.1
Total	71,072.0	64,720.7	66,881.4	202,674.2

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-4 and Table 2-5.[10,11] Table 2-4 shows the average hourly distribution of MW for dispatchable units by offer prices for the first three months of 2013. Table 2-5 shows the average hourly distribution of MW for self-scheduled units by offer prices for the first three months of 2013. Of the dispatchable MW offered by combustion turbines (CT), 27.7 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

Table 2-4 Distribution of MW for dispatchable unit offer prices: January through March of 2013

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	61.2%	13.8%	3.5%	3.5%	1.0%	82.9%
CT	0.0%	38.3%	21.4%	8.0%	27.7%	4.2%	99.6%
Diesel	0.0%	7.3%	51.8%	7.7%	1.2%	0.8%	68.9%
Hydro	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.3%
Nuclear	0.0%	9.8%	0.0%	0.0%	0.0%	0.0%	9.8%
Pumped Storage	0.0%	51.5%	0.0%	0.0%	0.0%	0.0%	51.5%
Solar	0.0%	44.1%	0.0%	0.0%	0.0%	0.0%	44.1%
Steam	0.0%	50.4%	9.9%	0.7%	0.1%	0.0%	61.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	26.0%	30.3%	0.0%	0.0%	0.0%	0.0%	56.3%
All Dispatchable Offers	0.7%	40.6%	10.4%	2.4%	6.1%	1.0%	61.3%

Table 2-5 Distribution of MW for self-scheduled unit offer prices: January through March of 2013

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	14.3%	2.7%	0.1%	0.0%	0.0%	17.1%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%
Diesel	0.0%	30.8%	0.1%	0.0%	0.0%	0.2%	31.1%
Hydro	0.0%	98.5%	0.0%	0.0%	0.0%	1.2%	99.7%
Nuclear	0.0%	90.2%	0.0%	0.0%	0.0%	0.0%	90.2%
Pumped Storage	0.0%	48.5%	0.0%	0.0%	0.0%	0.0%	48.5%
Solar	7.3%	48.6%	0.0%	0.0%	0.0%	0.0%	55.9%
Steam	0.0%	25.5%	13.1%	0.0%	0.3%	0.1%	38.9%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	11.6%	32.1%	0.0%	0.0%	0.0%	0.0%	43.7%
All Self-Scheduled Offers	0.3%	32.2%	5.9%	0.0%	0.1%	0.1%	38.7%

Demand

The PJM system peak load for the first three months 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2012.

10 Each range in the tables is greater than or equal to the lower value and less than the higher value.
11 The unit type battery is not included in these tables because batteries do not make energy offers.

Table 2-6 shows the coincident peak loads for the first three months of 1999 through 2013.

Table 2-6 Actual PJM footprint peak loads: January through March of 1999 to 2013[12]

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Thu, January 14	18	40,413	NA	NA
2000	Thu, January 27	19	42,445	2,032	5.0%
2001	Tue, January 02	19	41,142	(1,303)	(3.1%)
2002	Wed, January 02	19	39,458	(1,684)	(4.1%)
2003	Thu, January 23	19	54,670	15,212	38.6%
2004	Mon, January 26	19	53,620	(1,050)	(1.9%)
2005	Tue, January 18	19	96,362	42,742	79.7%
2006	Mon, February 13	20	100,065	3,703	3.8%
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012	Tue, January 03	19	122,539	11,880	10.7%
2013	Tue, January 22	19	126,632	4,093	3.3%

Figure 2-2 shows the peak loads for the first three months of 1999 through 2013.

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

Figure 2-2 PJM footprint calendar year peak loads: January through March of 1999 to 2013[13]

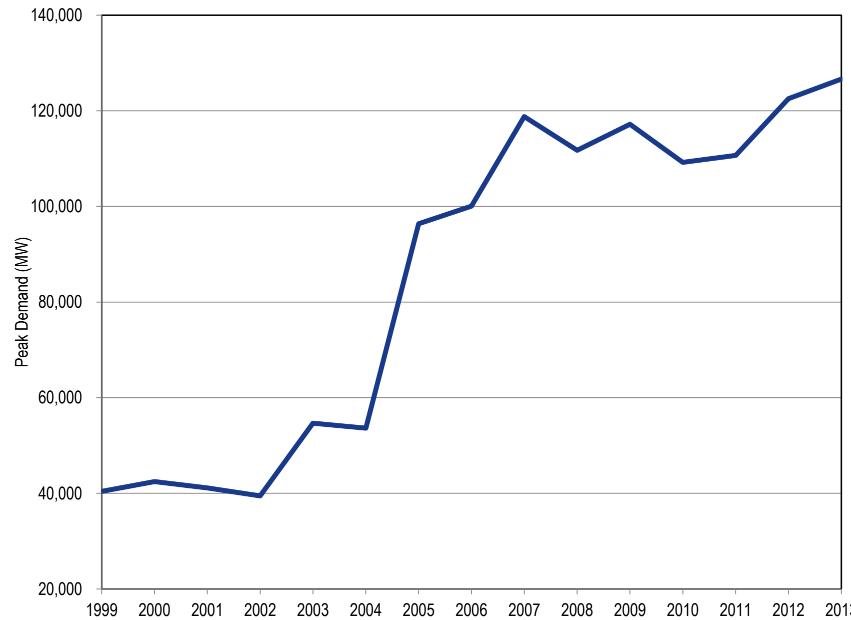
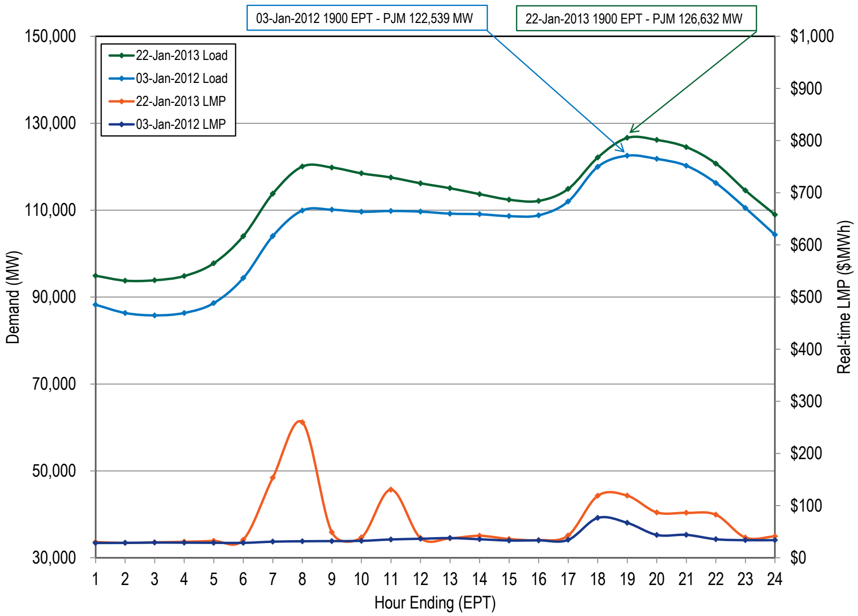


Figure 2-3 compares the peak load days in the first three months of 2012 and 2013. In every hour on January 22, 2013, the average hourly real-time load was higher than the average hourly real-time load on January 3, 2012. The average hourly real-time LMP peaked at $259.80 on January 22, 2013 and peaked at $76.50 on January 3, 2012. The higher real-time LMP for hours 7, 8 and 11 on January 22, 2013 was triggered by a large MW unit tripping resulting in loss of reserves. Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. The abrupt change in generation output resulted in energy units being redispatched to increase reserves for meeting ancillary service requirements. The joint optimization takes into account the lost opportunity cost of lowered generation in calculating LMPs and the incremental cost to maintain reserves. During the hours 7, 8 and 9 of January 22, 2013 higher LMPs reflect the

13 For additional information on the "PJM Integration Period", see the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

lost opportunity cost of generators providing reserve at the expense of not providing energy.

Figure 2-3 PJM peak-load comparison: Tuesday, January 22, 2013, and Tuesday, January 3, 2012



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first three months of 2013 indicate moderate concentration in the base load 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 the first three months of 2013. 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.

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 2-7).

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
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[15]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first three months of 2013 was moderately concentrated (Table 2-7).

14 A unit is classified as base load if it runs for more than 50 percent of the total hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of the total hours, and as peak if it runs for less than 10 percent of the total hours.

15 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)

Table 2-7 PJM hourly Energy Market HHI: January through March, 2012[16] and 2013

	Hourly Market HHI (Jan - Mar, 2012)	Hourly Market HHI (Jan - Mar, 2013)
Average	1235	1200
Minimum	1107	1047
Maximum	1499	1409
Highest market share (One hour)	28%	28%
Average of the highest hourly market share	22%	21%
# Hours	2,183	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

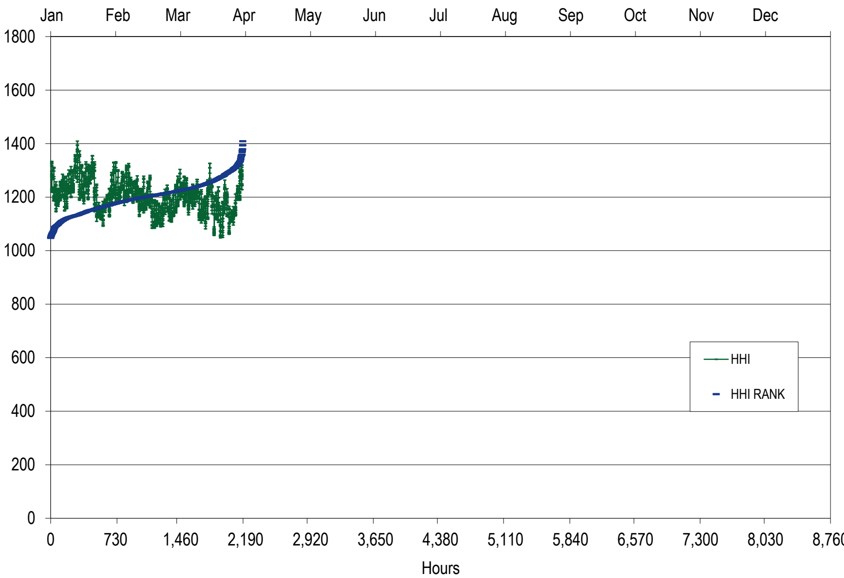
Table 2-8 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-8 PJM hourly Energy Market HHI (By supply segment): January through March, 2012 and 2013

	Jan - Mar, 2012			Jan - Mar, 2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1110	1239	1496	1082	1205	1410
Intermediate	1160	2916	7597	1204	3526	8784
Peak	966	6682	10000	914	6987	10000

Figure 2-4 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

Figure 2-4 PJM hourly Energy Market HHI: January through March, 2013



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service. 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.

Levels of offer capping have historically been low in PJM, as shown in Table 2-9. The offer capping percentages shown in Table 2-9 include all the units that are committed on their cost schedule, when their price schedule is

16 This analysis includes all hours in the first three months of 2013, regardless of congestion.

available. This includes units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, as well as units that are committed for reliability reasons to provide black start and reactive service.

Table 2-9 Offer-capping statistics: January through March, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.2%	0.2%	0.1%
2010	0.6%	0.2%	0.1%	0.0%
2011	0.6%	0.2%	0.0%	0.0%
2012	1.9%	1.3%	0.1%	0.2%
2013	3.6%	2.2%	4.1%	2.1%

Table 2-10 presents data on the frequency with which units were offer capped in the first three months of 2012 and 2013.

Table 2-10 Real-time offer-capped unit statistics: January through March, 2012 and 2013

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Mar)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2013	11	0	0	0	0	29
90%	2012	0	0	0	0	3	53
	2013	8	0	0	0	0	5
80% and < 90%	2012	2	0	0	0	0	7
	2013	4	0	0	1	0	2
75% and < 80%	2012	1	0	0	0	0	3
	2013	1	0	0	0	0	2
70% and < 75%	2012	2	0	0	0	0	7
	2013	2	0	0	0	0	9
60% and < 70%	2012	2	0	0	1	0	15
	2013	0	0	0	0	2	11
50% and < 60%	2012	2	0	0	2	2	18
	2013	0	0	3	0	1	26
25% and < 50%	2012	4	0	3	1	1	16
	2013	0	0	1	0	3	16
10% and < 25%	2012	0	1	2	1	3	14

Table 2-10 shows that a significant number of units are offer capped for 90 percent or more of their run hours in the first three months of 2013. The increase in the number of units that are capped for a high percentage of their run hours reflects the units that are committed specifically for reliability reasons.

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.

Local Market Structure

In the first three months of 2013, the AEP, AP, ATSI, BGE, ComEd, Dominion, PECO, PENELEC, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 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 the first three months of 2013.[17] The AECO, DAY, DEOK, DLCO, DPL, JCPL, Met-Ed and RECO Control Zones were not affected by constraints binding for 25 or more hours.

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, 2013, through March 31, 2013. 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

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

does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 2-11 Three pivotal supplier test details for regional constraints: January through March, 2013

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	282	332	13	2	11
	Off Peak	172	282	12	3	8
AP South	Peak	278	419	9	1	9
	Off Peak	305	476	9	1	8
Bedington - Black Oak	Peak	156	139	11	2	10
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	463	619	16	2	14
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	456	533	12	1	10
	Off Peak	NA	NA	NA	NA	NA

Table 2-12 Summary of three pivotal supplier tests applied for regional constraints: January through March, 2013

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	570	50	9%	14	2%	28%
	Off Peak	378	41	11%	8	2%	20%
AP South	Peak	2,936	158	5%	26	1%	16%
	Off Peak	1,632	67	4%	9	1%	13%
Bedington - Black Oak	Peak	11	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	8	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	5	1	20%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA

Table 2-11 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 for the regional 500 kV constraints.

The three pivotal supplier test is applied every time the PJM market 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 2-12 provides, for the identified 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.

Ownership of Marginal Resources

Table 2-13 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[18] The contribution of each marginal resource to price at each load bus is calculated for the first three months of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first three months of 2013, the offers of one company contributed 26.2 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 58.1 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first three months of 2012, the offers of one company contributed 24.4 percent of the real time, load-weighted PJM system LMP and offers of the top four

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

companies contributed 58.5 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through March, 2012 and 2013

2012 (Jan - Mar)		2013 (Jan - Mar)	
Company	Percent of Price	Company	Percent of Price
1	24.4%	1	26.2%
2	15.7%	2	11.4%
3	9.4%	3	10.7%
4	8.9%	4	9.9%
5	8.1%	5	7.8%
6	4.2%	6	5.2%
7	3.9%	7	4.4%
8	3.9%	8	3.5%
9	3.7%	9	3.3%
Other (37 companies)	17.7%	Other (45 companies)	17.8%

Table 2-14 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[19] The contribution of each marginal resource to price at each load bus is calculated for the first three months of 2013, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-14 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): January through March, 2012 and 2013

2012 (Jan - Mar)		2013 (Jan - Mar)	
Company	Percent of Price	Company	Percent of Price
1	17.4%	1	20.1%
2	8.7%	2	9.0%
3	7.7%	3	8.7%
4	7.5%	4	4.0%
5	6.8%	5	3.8%
6	3.9%	6	3.7%
7	3.9%	7	3.6%
8	3.6%	8	3.4%
9	2.9%	9	3.1%
Other (98 companies)	37.6%	Other (115 companies)	40.6%

19 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 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 up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market that can set price via their offers and bids.

Table 2-15 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2013, coal units were 61.5 percent and natural gas units were 30.8 percent of the total marginal resources. In the first three months of 2012, coal units were 60.9 percent and natural gas units were 27.3 percent of the total marginal resources.[20]

Table 2-15 Type of fuel used (By real-time marginal units): January through March, 2012 and 2013

Fuel Type	2012 (Jan - Mar)	2013 (Jan - Mar)
Coal	60.9%	61.5%
Gas	27.3%	30.8%
Municipal Waste	0.2%	0.1%
Oil	4.3%	1.8%
Other	0.2%	0.1%
Uranium	0.0%	0.0%
Wind	7.1%	5.7%

Table 2-16 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first three months of 2013, Up-to Congestion transactions were 95.4 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 84.8 percent of the total marginal resources in the first three months of 2012.

20 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, Volume I, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. Starting from *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on resources that were marginal in dispatch (SCED). See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 2-16 Day-ahead marginal resources by type/fuel: January through March, 2012 and 2013

Type/Fuel	2012 (Jan - Mar)	2013 (Jan - Mar)
Up-to Congestion Transaction	84.8%	95.4%
DEC	5.8%	1.2%
INC	5.5%	1.0%
Coal	2.7%	1.6%
Gas	0.9%	0.7%
Price Sensitive Demand	0.1%	0.0%
Dispatchable Transaction	0.1%	0.1%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Total	100.0%	100.0%

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.[21] 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 2-17 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 dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

Table 2-17 Average, real-time marginal unit markup index (By price category): January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.07)	($2.75)	29.5%	(0.08)	($3.04)	18.0%
$25 to $50	(0.06)	($2.87)	53.1%	(0.04)	($2.55)	62.1%
$50 to $75	0.02	($0.78)	3.3%	0.01	($0.60)	6.7%
$75 to $100	0.32	$27.64	0.2%	0.04	$3.39	1.5%
$100 to $125	0.22	$22.17	0.4%	0.02	$2.23	1.2%
$125 to $150	0.49	$62.73	0.1%	0.02	$2.27	0.9%
>= $150	0.04	$8.01	5.0%	0.01	$0.14	4.1%

Day-Ahead Mark Up Conduct

Table 2-18 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 2-18 Average marginal unit markup index (By offer price category): January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.55)	27.4%	(0.05)	($1.55)	17.1%
$25 to $50	(0.07)	($3.40)	70.3%	(0.05)	($2.96)	77.1%
$50 to $75	0.03	$0.97	2.3%	0.01	($2.48)	5.2%
$75 to $100	0.00	$0.00	0.0%	0.08	$6.63	0.5%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	0.00	$0.00	0.0%	0.00	$0.00	0.0%
>= $150	0.00	$0.00	0.0%	0.00	$0.00	0.0%

21 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

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.[22]

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 calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the 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 2-19 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 2-19 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-17.

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

Table 2-19 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March, 2012 and 2013[23]

		2012 (Jan - Mar)		2013 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($2.05)	80.2%	($1.08)	40.2%
Gas	CC	($0.23)	9.1%	($1.42)	53.0%
Gas	CT	($0.20)	7.8%	($0.26)	9.5%
Gas	Diesel	$0.00	0.0%	$0.00	(0.0%)
Gas	Steam	($0.01)	0.4%	$0.07	(2.4%)
Municipal Waste	Diesel	$0.00	0.0%	$0.00	0.0%
Municipal Waste	Steam	$0.04	(1.7%)	$0.00	(0.0%)
Oil	CT	$0.00	(0.0%)	($0.00)	0.0%
Oil	Diesel	$0.00	(0.0%)	$0.00	(0.0%)
Oil	Steam	($0.11)	4.4%	($0.00)	0.1%
Other	Solar	$0.00	0.0%	$0.00	(0.0%)
Other	Steam	($0.01)	0.3%	($0.00)	0.1%
Uranium	Steam	$0.00	0.0%	$0.00	0.0%
Wind	Wind	$0.01	(0.4%)	$0.01	(0.4%)
TOTAL		($2.55)	100.0%	($2.69)	100.0%

Markup Component of Real-Time System Price

Table 2-20 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In the first three months of 2013, -$2.69 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first three months of 2013, the markup component of LMP was -$3.37 per MWh off peak and -$2.02 per MWh on peak. In comparison, in the first three months of 2012, -$2.55 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first three months of 2012, the markup component of LMP was -$3.02 per MWh off peak and -$2.10 per MWh on peak.

23 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

Table 2-20 Monthly markup components of real-time load-weighted LMP: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.25)	($3.51)	($2.98)	($4.05)	($4.42)	($3.70)
Feb	($2.07)	($2.92)	($1.26)	($2.61)	($3.87)	($1.38)
Mar	($2.24)	($2.51)	($2.00)	($1.33)	($1.85)	($0.80)
Total	($2.55)	($3.02)	($2.10)	($2.69)	($3.37)	($2.02)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-21. While all were negative, the smallest zonal all hours average markup component for the first three months of 2013 was in the BGE Control Zone, -$3.03 per MWh, while the highest all hours' average zonal markup component for the first three months of 2013 was in the RECO Control Zone, -$1.20 per MWh. On peak, the smallest annual average zonal markup was in the PECO Control Zone, -$2.41 per MWh, while the highest annual average zonal markup was in the RECO Control Zone, -$0.19 per MWh.

Table 2-21 Average real-time zonal markup component: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($2.52)	($3.53)	($1.51)	($2.90)	($3.58)	($2.22)
AEP	($2.73)	($3.17)	($2.28)	($2.73)	($3.05)	($2.40)
APS	($2.53)	($2.99)	($2.07)	($2.75)	($3.39)	($2.11)
ATSI	($2.88)	($3.43)	($2.35)	($2.60)	($3.00)	($2.22)
BGE	($2.30)	($1.89)	($2.71)	($3.03)	($4.05)	($1.99)
ComEd	($2.67)	($3.19)	($2.19)	($2.55)	($3.26)	($1.86)
DAY	($2.91)	($3.31)	($2.53)	($2.69)	($3.12)	($2.27)
DEOK	($2.87)	($3.17)	($2.58)	($2.65)	($3.11)	($2.20)
Dominion	($2.03)	($1.86)	($2.20)	($2.90)	($3.94)	($1.82)
DPL	($2.46)	($3.61)	($1.28)	($2.98)	($3.63)	($2.31)
DUQ	($2.67)	($2.98)	($2.36)	($2.52)	($3.00)	($2.06)
JCPL	($2.55)	($3.48)	($1.67)	($2.41)	($3.76)	($1.13)
Met-Ed	($2.62)	($3.53)	($1.75)	($2.70)	($3.38)	($2.05)
PECO	($2.53)	($3.55)	($1.55)	($2.94)	($3.49)	($2.41)
PENELEC	($2.75)	($3.41)	($2.11)	($2.50)	($3.13)	($1.89)
Pepco	($1.82)	($2.02)	($1.64)	($2.98)	($3.92)	($2.07)
PPL	($2.65)	($3.54)	($1.80)	($2.84)	($3.55)	($2.15)
PSEG	($2.53)	($3.48)	($1.65)	($1.86)	($2.88)	($0.89)
RECO	($2.46)	($3.63)	($1.44)	($1.20)	($2.34)	($0.19)

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 2-22 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-22 Average real-time markup component (By price category): January through March, 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.67)	21.0%	($0.23)	8.3%
$25 to $50	($2.50)	74.1%	($2.28)	81.2%
$50 to $75	$0.27	2.7%	$0.02	5.3%
$75 to $100	$0.23	1.1%	($0.07)	1.4%
$100 to $125	$0.07	0.2%	($0.14)	0.7%
$125 to $150	$0.04	0.1%	($0.04)	0.2%
>= $150	$0.01	0.0%	$0.03	0.4%

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 2-23.

Table 2-23 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March, 2012 and 2013

		2012 (Jan - Mar)		2013 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.94)	72.0%	($1.35)	49.3%
Gas	Steam	($0.62)	23.0%	($1.32)	48.2%
Oil	Steam	($0.10)	3.8%	($0.01)	0.2%
Gas	CT	($0.03)	1.2%	($0.06)	2.3%
Municipal Waste	Steam	($0.00)	0.1%	($0.00)	0.1%
Wind	Wind	($0.00)	0.0%	$0.00	0.0%
Total		($2.70)	100.0%	($2.74)	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 2-24 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-24 Monthly markup components of day-ahead, load-weighted LMP: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Total	($2.70)	($2.61)	($2.79)	($2.74)	($1.94)	($3.55)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-25.

Table 2-25 Day-ahead, average, zonal markup component: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.32)	($3.47)	($3.16)	($2.98)	($2.31)	($3.67)
AEP	($2.55)	($2.35)	($2.75)	($2.62)	($1.76)	($3.48)
AP	($2.67)	($2.62)	($2.72)	($2.72)	($1.92)	($3.52)
ATSI	($2.68)	($2.56)	($2.81)	($2.75)	($1.85)	($3.70)
BGE	($2.85)	($2.93)	($2.78)	($2.77)	($2.14)	($3.41)
ComEd	($2.26)	($1.92)	($2.62)	($2.58)	($1.67)	($3.53)
DAY	($2.58)	($2.34)	($2.83)	($2.75)	($1.82)	($3.72)
DEOK	($2.55)	($2.41)	($2.69)	($2.63)	($1.68)	($3.60)
DLCO	($2.64)	($2.58)	($2.70)	($2.67)	($1.82)	($3.56)
DPL	($3.29)	($3.48)	($3.11)	($2.89)	($1.97)	($3.79)
Dominion	($2.51)	($2.35)	($2.66)	($2.69)	($2.02)	($3.32)
JCPL	($3.31)	($3.65)	($2.95)	($3.50)	($3.33)	($3.68)
Met-Ed	($2.98)	($2.94)	($3.02)	($2.90)	($2.24)	($3.59)
PECO	($3.27)	($3.41)	($3.13)	($2.84)	($2.02)	($3.69)
PENELEC	($2.77)	($2.65)	($2.89)	($2.70)	($1.80)	($3.65)
PPL	($3.04)	($3.05)	($3.04)	($2.99)	($2.34)	($3.65)
PSEG	($3.13)	($3.26)	($2.99)	($2.81)	($2.03)	($3.67)
Pepco	($2.72)	($2.75)	($2.69)	($2.74)	($2.11)	($3.39)
RECO	($2.99)	($3.16)	($2.80)	($2.78)	($1.90)	($3.76)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-26.

Table 2-26 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-26 Average, day-ahead markup (By LMP category): January through March, 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.35)	13.0%	($2.03)	3.1%
$25 to $50	($3.39)	86.2%	($3.74)	90.8%
$50 to $75	($0.61)	0.7%	$1.76	5.4%
$75 to $100	($0.95)	0.2%	$0.55	0.5%
$100 to $125	$0.00	0.0%	$0.02	0.2%
$125 to $150	$0.00	0.0%	$0.00	0.0%
>= $150	$0.00	0.0%	$0.00	0.0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[24] 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.[25] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[26,27]

24 110 FERC ¶ 61,053 (2005).
25 OA, Schedule 1 § 6.4.2.
26 114 FERC ¶ 61, 076 (2006).
27 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[28]

Table 2-27 shows, by month, the number of FMUs and AUs in 2011 and 2012. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

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

Table 2-27 Number of frequently mitigated units and associated units (By month): 2012 and January through March 2013

	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86				
May	23	14	47	84				
June	22	13	48	83				
July	25	11	50	86				
August	25	23	43	91				
September	17	6	33	56				
October	10	18	14	42				
November	9	21	10	40				
December	14	17	10	41				

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.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through March, 2013

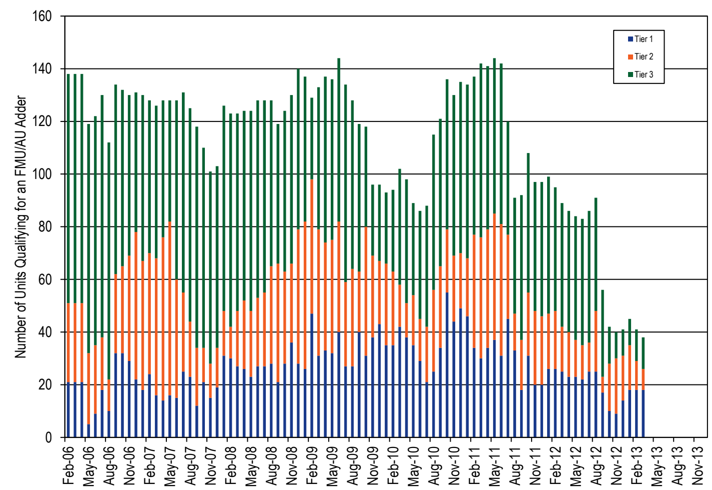


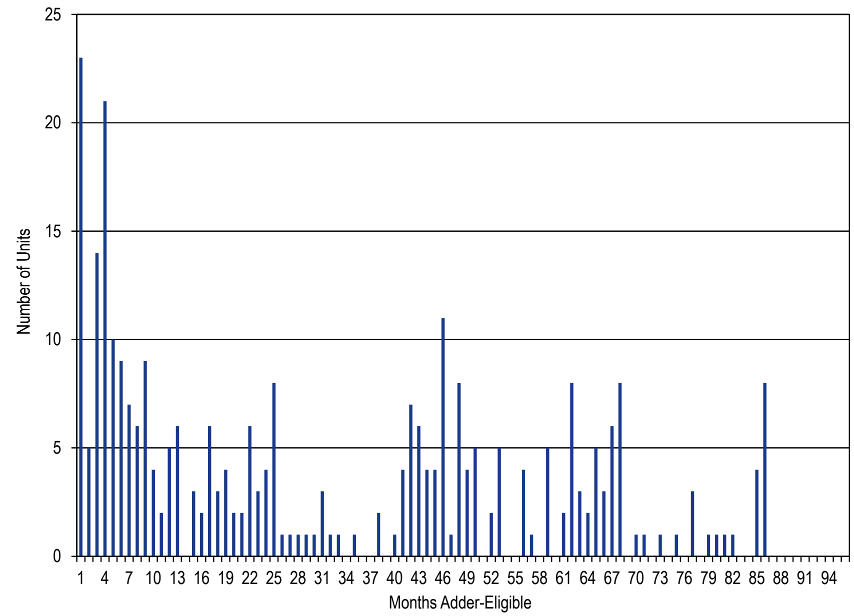
Table 2-28 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and during the first three months of 2013. Of the 48 units eligible in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

Table 2-28 Frequently mitigated units and associated units total months eligible: 2012 and January through March, 2013

Months Adder-Eligible	FMU & AU Count	
	2012	2013
1	25	7
2	12	6
3	4	35
4	9	
5	2	
6	4	
7	14	
8	16	
9	15	
10	5	
11	2	
12	25	
Total	133	48

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 March 31, 2013, there have been 309 unique units that have qualified for an FMU adder in at least one month. Of these 309 units, no unit qualified for an adder in all potential months. Eight units qualified in 86 of the 87 possible months, and 110 of the 309 units (35.6 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 March, 2013



Market Performance: Load and LMP

The PJM system load and average 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

PJM average real-time load in the first three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first three months of 2013 increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW.

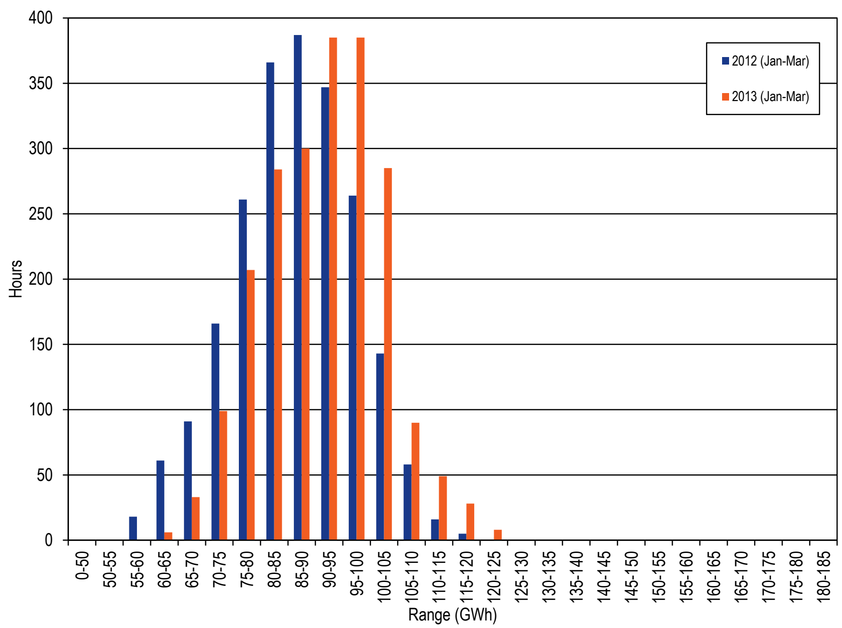
The day-ahead load growth was higher than the real-time load growth because of the continued growth of up-to congestion transactions. If the first three months of 2013 up-to congestion transactions had been held to the first three months of 2012 levels, the day-ahead load, including DECs and up-to congestion transactions, would have increased 3.4 percent instead of 11.1 percent and day-ahead load growth would have been lower than the real-time load growth.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for the first three months of 2012 and 2013.[29]

Figure 2-7 PJM real-time accounting load: January through March of 2012 and 2013[30]



29 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.
30 Each range on the vertical axis includes the start value and excludes the end value.

PJM Real-Time, Average Load

Table 2-29 presents summary real-time load statistics for the first three months during the 16 year period 1998 to 2013. 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.[31]

Table 2-29 PJM real-time average hourly load: January through March of 1998 through 2013

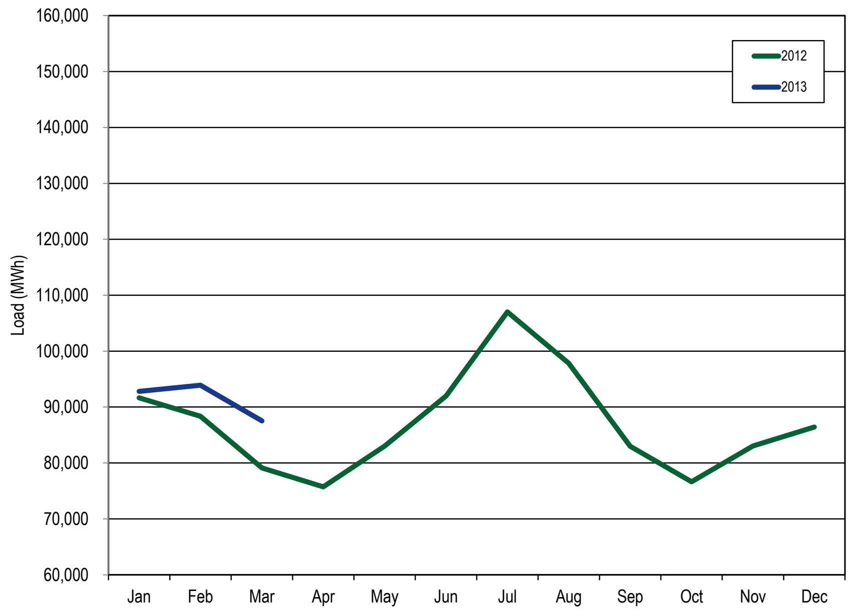
	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,019	3,762	NA	NA
1999	29,784	4,027	6.3%	7.0%
2000	30,367	4,624	2.0%	14.8%
2001	31,254	3,846	2.9%	(16.8%)
2002	29,968	4,083	(4.1%)	6.1%
2003	39,249	5,546	31.0%	35.8%
2004	39,549	5,761	0.8%	3.9%
2005	71,388	8,966	80.5%	55.6%
2006	80,179	8,977	12.3%	0.1%
2007	84,586	12,040	5.5%	34.1%
2008	82,235	10,184	(2.8%)	(15.4%)
2009	81,170	11,718	(1.3%)	15.1%
2010	81,121	10,694	(0.1%)	(8.7%)
2011	81,018	10,273	(0.1%)	(3.9%)
2012	86,329	10,947	6.6%	6.6%
2013	91,337	10,610	5.8%	(3.1%)

31 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.

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

Figure 2-8 PJM real-time monthly average hourly load: January 2012 through March 2013



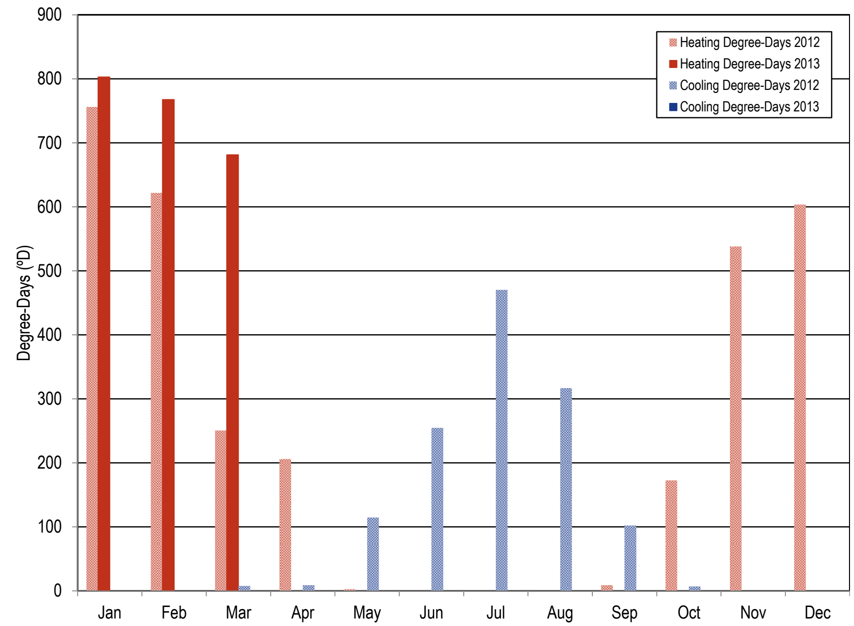
PJM real-time load is significantly affected by temperature. Figure 2-9 compares the total PJM monthly heating and cooling degree days in the first three months of 2013 with those in 2012.[32,33,34] The figure shows that in each of the first three months of 2013, the number of heating degree days was higher than in each of the first three months of 2012.

32 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degree F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).

33 For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 22 (February 28, 2013), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

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

Figure 2-9 PJM Heating and Cooling Degree Days: January of 2012 through March of 2013[35]



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.

35 The version of this figure in the *2012 Quarterly State of the Market Report for PJM: January through September* reported the heating and cooling degree days using hourly totals by month. This figure properly reports the degree days using daily totals by month.

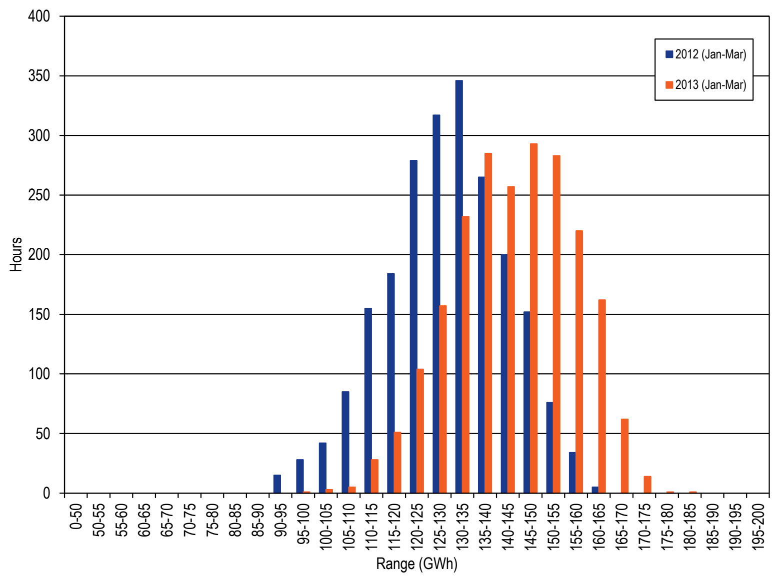
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[36] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a 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 four types of cleared demand bids.[37]

PJM Day-Ahead Load Duration

Figure 2-10 shows the hourly distribution of PJM day-ahead load for the first three months of 2012 and 2013.

Figure 2-10 PJM day-ahead load: January through March of 2012 and 2013



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

37 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.

PJM Day-Ahead, Average Load

Table 2-30 presents summary day-ahead load statistics for the first three months of 13-year period 2001 to 2013.

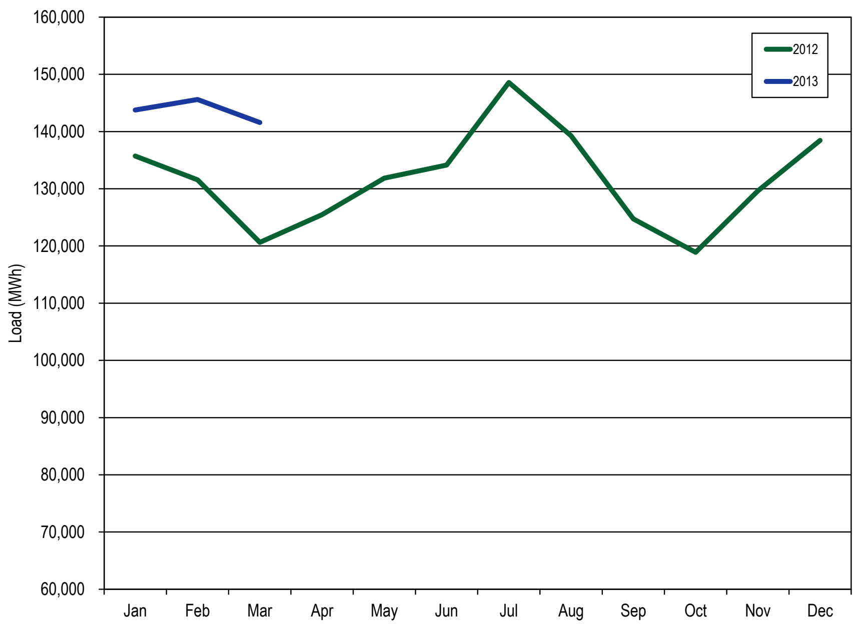
Table 2-30 PJM day-ahead average load: January through March of 2001 through 2013

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Mar)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,731	0	33,731	4,557	5	4,557	NA	NA	NA
2002	33,938	37	33,975	4,944	118	4,960	0.6%	11,350.0%	0.7%
2003	46,743	292	47,034	6,848	319	6,841	37.7%	686.0%	38.4%
2004	46,259	627	46,885	5,624	412	5,591	(1.0%)	114.8%	(0.3%)
2005	86,248	1,093	87,341	9,915	710	9,810	86.4%	74.5%	86.3%
2006	93,295	2,949	96,244	9,377	1,419	9,453	8.2%	169.7%	10.2%
2007	104,033	4,666	108,699	12,140	1,464	12,601	11.5%	58.3%	12.9%
2008	100,046	5,949	105,995	10,421	1,464	10,677	(3.8%)	27.5%	(2.5%)
2009	94,583	7,783	102,366	12,828	1,784	13,619	(5.5%)	30.8%	(3.4%)
2010	93,559	7,453	101,012	11,907	2,276	11,937	(1.1%)	(4.2%)	(1.3%)
2011	89,478	17,638	107,116	11,157	2,654	11,890	(4.4%)	136.7%	6.0%
2012	92,415	36,844	129,258	11,542	4,088	13,163	3.3%	108.9%	20.7%
2013	96,840	46,745	143,585	11,193	8,831	13,120	4.8%	26.9%	11.1%

PJM Day-Ahead, Monthly Average Load

Figure 2-11 compares the day-ahead, monthly average hourly loads of 2013 with those of 2012.

Figure 2-11 PJM day-ahead monthly average hourly load: January 2012 through March 2013



Real-Time and Day-Ahead Load

Table 2-31 presents summary statistics for the first three months of 2012 and 2013 day-ahead and real-time loads.

Table 2-31 Cleared day-ahead and real-time load (MWh): January through March of 2012 and 2013

		Day Ahead					Real Time	Average Difference	
	(Jan-Mar)	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	2012	83,557	895	7,962	36,844	129,258	86,329	42,929	(1,876)
	2013	88,395	943	7,502	46,745	143,585	91,337	52,248	(1,998)
Median	2012	84,076	886	7,852	36,671	129,802	86,486	43,316	(1,207)
	2013	89,132	873	7,188	46,492	144,317	91,993	52,325	(1,355)
Standard Deviation	2012	10,297	135	1,584	4,088	13,163	10,947	2,216	(3,457)
	2013	9,989	223	1,550	8,831	13,120	10,610	2,510	(7,871)
Peak Average	2012	90,231	963	8,501	37,274	136,970	92,984	43,986	(1,790)
	2013	95,586	1,004	8,190	46,276	151,056	98,579	52,477	(1,989)
Peak Median	2012	89,908	952	8,256	37,204	136,171	92,368	43,803	(1,657)
	2013	95,116	857	7,760	46,487	151,966	98,355	53,611	(635)
Peak Standard Deviation	2012	6,764	120	1,377	3,967	9,296	7,549	1,747	(3,597)
	2013	6,484	237	1,514	7,734	9,885	7,400	2,485	(6,763)
Off-Peak Average	2012	77,485	833	7,471	36,452	122,242	80,273	41,968	(1,955)
	2013	82,098	889	6,899	47,155	137,041	84,994	52,047	(2,006)
Off-Peak Median	2012	77,190	830	7,276	36,179	122,389	79,600	42,789	(666)
	2013	81,676	882	6,556	46,492	136,783	84,250	52,533	(515)
Off-Peak Standard Deviation	2012	9,138	117	1,602	4,159	12,207	10,005	2,202	(3,559)
	2013	8,087	195	1,311	9,675	12,068	8,777	3,291	(7,695)

Figure 2-12 shows the first three months average 2013 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.

Figure 2-12 Day-ahead and real-time loads (Average hourly volumes): January through March of 2013

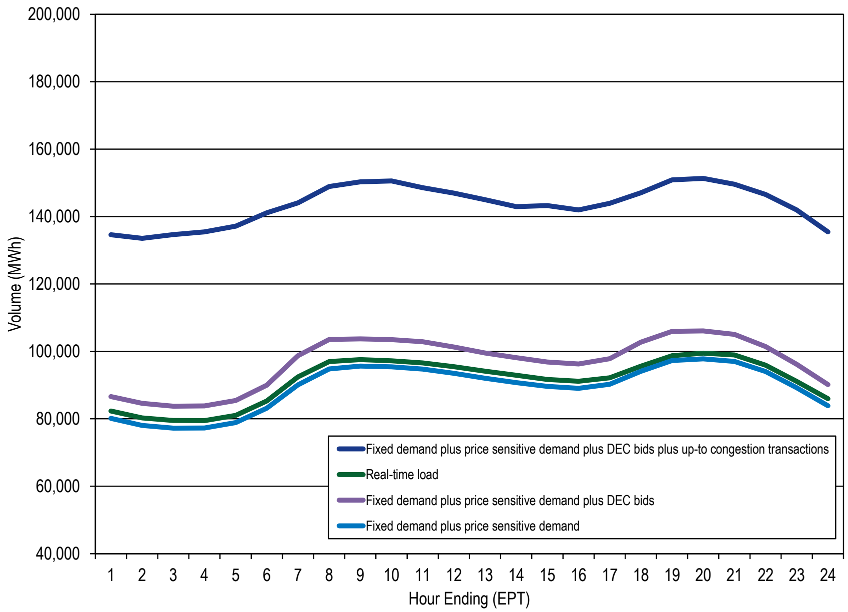
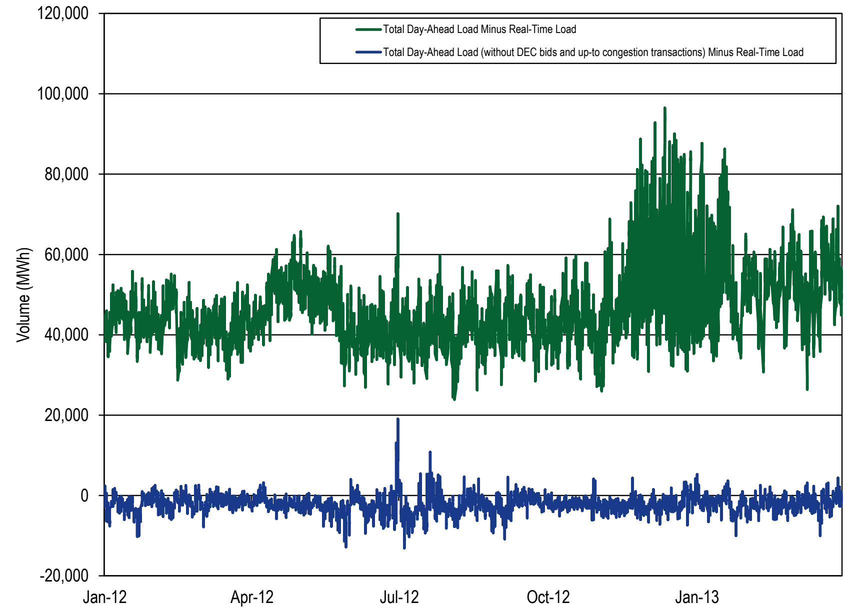


Figure 2-13 shows the difference between the day-ahead and real-time average daily loads in 2012 through the first three months of 2013.

Figure 2-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2012 through March of 2013



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW.

The day-ahead generation growth was higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If the first three months of 2013 up-to congestion transactions had been held to first three months of 2012 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 3.9 percent instead of 11.4 percent and day-ahead generation growth would have been lower than the real-time generation growth.

The real-time and day-ahead generation have been calculated have been calculated as net generation since 2003. What is termed negative generation, included in the average hourly generation for real time and day ahead, consists of power used by pumped storage hydro units when they are pumping and not generating, other units that draw station power when coming online and synchronized reserve units that use power while synchronized but not generating. These sources of negative generation are actually load on the system, although they are not currently included in the average hourly real-time and day-ahead load.

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:[38]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, including a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[39]
- **Generator Offer.** Offer to supply a schedule of MWh and the corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply specified MWh and the 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.[40] 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 2-32 presents summary real-time generation statistics for the first three months of the 11-year period from 2003 through 2013.

Table 2-32 PJM real-time average hourly generation: January through March of 2003 through 2013

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	38,731	5,187	NA	NA
2004	37,790	4,660	(2.4%)	(10.2%)
2005	74,187	8,269	96.3%	77.4%
2006	82,550	7,921	11.3%	(4.2%)
2007	86,286	10,018	4.5%	26.5%
2008	86,690	9,375	0.5%	(6.4%)
2009	81,987	11,417	(5.4%)	21.8%
2010	81,676	12,801	(0.4%)	12.1%
2011	83,505	10,116	2.2%	(21.0%)
2012	88,068	11,177	5.5%	10.5%
2013	92,776	10,030	5.3%	(10.3%)

Table 2-33 presents summary day-ahead generation statistics for the first three months of the 11-year period from 2003 through 2013.

38 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 *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."
39 The definition of self-scheduled is based on the PJM "eMKT User Guide" (October, 2012), pp. 41-44.

40 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 2-33 PJM day-ahead average hourly generation: January through March of 2003 through 2013

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Mar)	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
2003	36,855	292	37,147	4,379	319	4,337	NA	NA	NA
2004	45,964	627	46,591	4,825	412	4,794	24.7%	114.8%	25.4%
2005	87,918	1,093	89,011	9,529	710	9,434	91.3%	74.5%	91.0%
2006	94,370	2,949	97,319	8,974	1,419	9,035	7.3%	169.7%	9.3%
2007	105,433	4,666	110,099	11,438	1,464	11,938	11.7%	58.3%	13.1%
2008	103,763	5,949	109,711	10,197	1,464	10,479	(1.6%)	27.5%	(0.4%)
2009	97,097	7,783	104,880	13,093	1,784	13,895	(6.4%)	30.8%	(4.4%)
2010	94,280	7,453	101,733	14,264	2,276	13,835	(2.9%)	(4.2%)	(3.0%)
2011	92,672	17,638	110,310	11,463	2,654	12,200	(1.7%)	136.7%	8.4%
2012	95,334	36,844	132,178	12,066	4,088	13,701	2.9%	108.9%	19.8%
2013	100,502	46,745	147,246	11,224	8,831	13,054	5.4%	26.9%	11.4%

Table 2-34 presents summary statistics for the first three months of 2012 and 2013 for day-ahead and real-time generation.

Table 2-34 Day-ahead and real-time generation (MWh): January through March of 2012 and 2013

		Day Ahead				Real Time	Average Difference	
	(Jan-Mar)	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	2012	88,942	6,392	36,844	132,178	88,068	874	44,110
	2013	94,829	5,673	46,745	147,246	92,776	2,053	54,471
Median	2012	89,373	6,345	36,671	132,597	88,079	1,294	44,518
	2013	95,320	5,702	46,492	148,031	93,346	1,974	54,685
Standard Deviation	2012	11,883	773	4,088	13,701	11,177	706	2,524
	2013	10,944	680	8,831	13,054	10,030	913	3,024
Peak Average	2012	96,169	6,557	37,274	140,000	94,441	1,728	45,559
	2013	102,331	6,085	46,276	154,692	99,495	2,835	55,196
Peak Median	2012	95,687	6,497	37,204	139,084	94,019	1,668	45,065
	2013	101,557	6,096	46,487	155,453	99,374	2,183	56,079
Peak Standard Deviation	2012	7,975	595	3,967	9,825	8,066	(90)	1,759
	2013	7,445	508	7,734	9,731	7,131	313	2,599
Off-Peak Average	2012	82,367	6,242	36,452	125,061	82,271	96	42,790
	2013	88,258	5,313	47,155	140,726	86,891	1,368	53,835
Off-Peak Median	2012	82,252	6,106	36,179	125,297	82,113	139	43,184
	2013	87,617	5,210	46,492	140,418	86,261	1,356	54,157
Off-Peak Standard Deviation	2012	11,006	879	4,159	12,823	10,435	571	2,388
	2013	9,147	602	9,675	12,072	8,367	780	3,705

Figure 2-14 shows the first three months average 2013 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.[41]

Figure 2-14 Day-ahead and real-time generation (Average hourly volumes): January through March of 2013

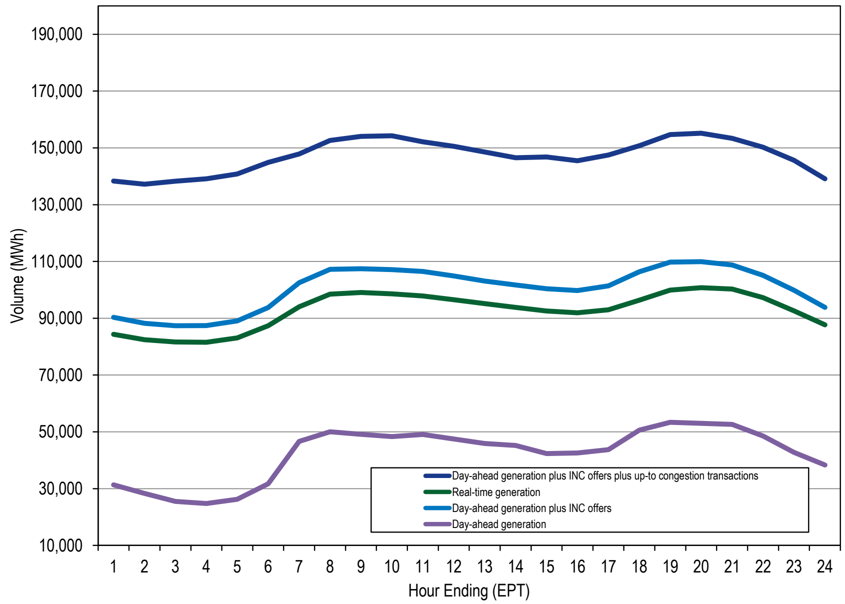


Figure 2-15 shows the difference between the day-ahead and real-time average daily generation in 2012 through the first three months of 2013.

Figure 2-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2012 through March of 2013

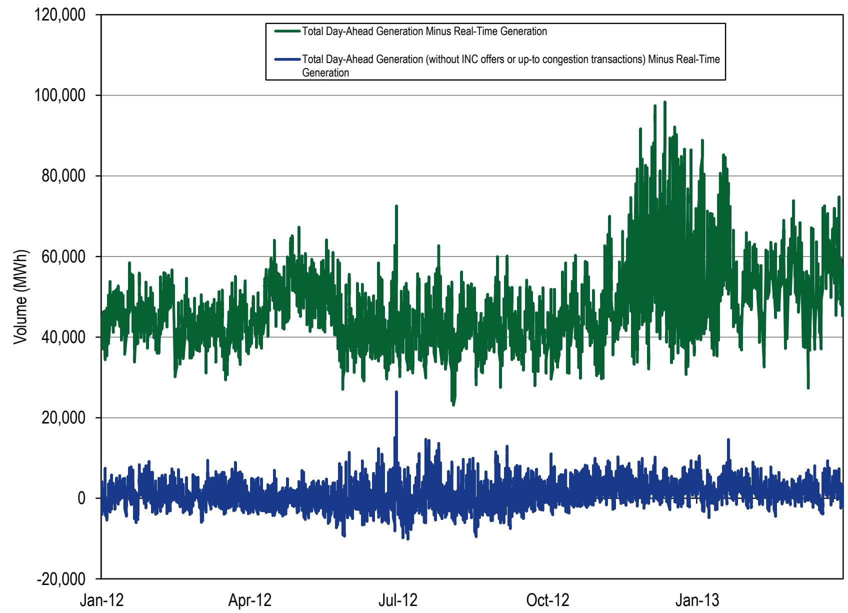


Figure 2-16 and Table 2-35 show the total difference between the PJM real-time generation and real-time load by zone in the first three months of 2013. Figure 2-16 is color coded on a scale where red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

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

Figure 2-16 PJM real-time generation less real-time load by zone (GWh): January through March of 2013

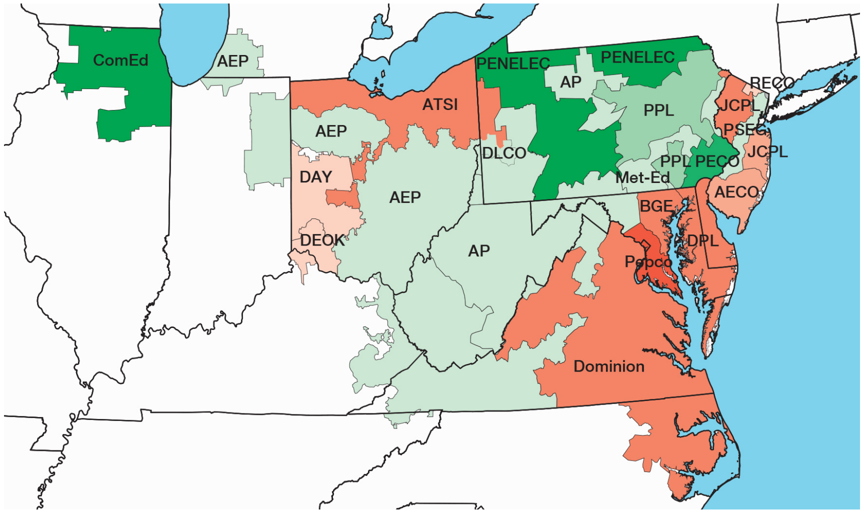


Table 2-35 PJM real-time generation less real-time load by zone (GWh): January through March of 2012 and 2013

	Zonal Generation and Load (GWh)					
	2012 (Jan-Mar)			2013 (Jan-Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	315.7	2,375.2	(2,059.5)	400.5	2,472.5	(2,072.0)
AEP	35,530.0	33,662.8	1,867.3	35,431.1	34,699.0	732.1
AP	11,160.2	11,995.8	(835.6)	14,090.8	12,833.1	1,257.7
ATSI	14,429.9	16,614.2	(2,184.3)	14,092.2	17,074.0	(2,981.8)
BGE	3,786.0	8,014.2	(4,228.2)	4,826.2	8,298.0	(3,471.8)
ComEd	32,497.1	23,604.9	8,892.2	31,380.5	24,356.2	7,024.2
DAY	3,827.8	4,189.5	(361.8)	4,026.8	4,317.1	(290.3)
DEOK	4,763.8	6,431.8	(1,668.0)	6,615.6	6,730.9	(115.2)
Dominion	20,084.5	22,326.9	(2,242.4)	20,993.3	24,333.0	(3,339.7)
DPL	1,710.4	4,427.9	(2,717.5)	1,602.2	4,838.0	(3,235.8)
DLCO	4,786.4	3,579.5	1,206.9	4,841.3	3,638.3	1,203.0
JCPL	2,782.6	5,275.0	(2,492.4)	1,881.6	5,527.1	(3,645.6)
Met-Ed	5,348.7	3,757.1	1,591.6	5,427.8	3,956.2	1,471.6
PECO	15,492.3	9,558.5	5,933.8	15,004.3	10,069.0	4,935.3
PENELEC	9,473.4	4,408.1	5,065.3	11,825.4	4,637.0	7,188.4
Pepco	1,668.5	7,373.3	(5,704.8)	2,161.9	7,625.7	(5,463.8)
PPL	13,235.9	10,364.3	2,871.6	13,815.7	10,996.3	2,819.4
PSEG	11,360.4	10,153.3	1,207.1	11,885.4	10,440.5	1,444.9
RECO	0.0	343.6	(343.6)	0.0	353.8	(353.8)

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[42] PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 19.9 percent and 18.3 percent higher in the first three months of 2013 than in the first three months of 2012 as a result of higher fuel costs and higher demand.[43] Natural

42 See the *2012 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.

43 There was an average increase of 7.1 heating degree days and an average reduction of 0.1 cooling degree days in the first three months of 2013 compared to the first three months of 2012 which meant overall increased demand.

gas prices were higher, particularly in eastern zones, while coal prices were constant or decreased. The fuel-cost-adjusted, load weighted LMP in the first three months of 2013 shows that the mix of fuel types and fuel costs resulted in slightly higher prices than would have occurred if fuel prices had remained at the same levels as in the first three months of 2012.

PJM Real-Time Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[44]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[45] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

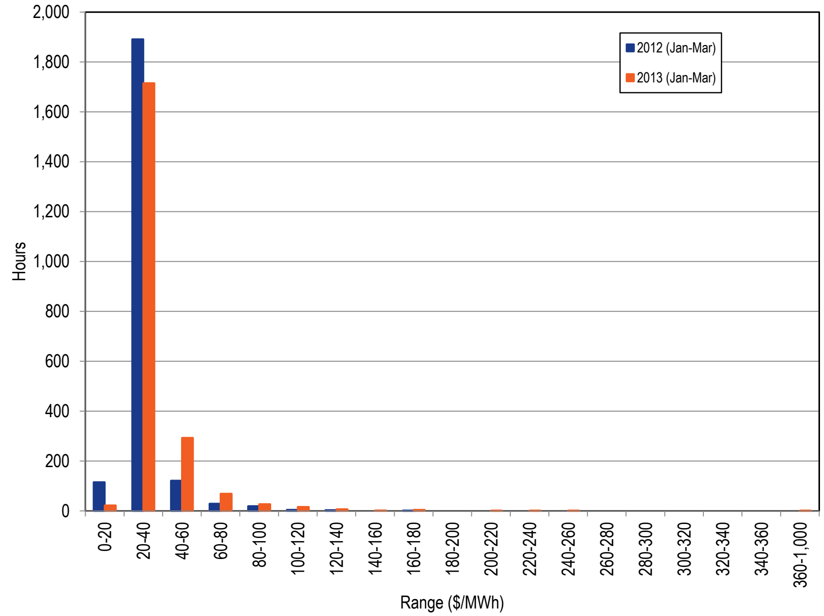
PJM Real-Time Average LMP Duration

Figure 2-17 shows the hourly distribution of PJM real-time average LMP for the first three months of 2012 and 2013.

44 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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

Figure 2-17 Average LMP for the PJM Real-Time Energy Market: January through March of 2012 and 2013



PJM Real-Time, Average LMP

Table 2-36 shows the PJM real-time, average LMP for the first three months of the 16-year period 1998 to 2013.[46]

Table 2-36 PJM real-time, average LMP (Dollars per MWh): January through March of 1998 through 2013

	Real-Time LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%

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, Load-Weighted, Average LMP

Table 2-37 shows the PJM real-time, load-weighted, average LMP for the first three months of the 16-year period 1998 to 2013.

Table 2-37 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through March of 1998 through 2013

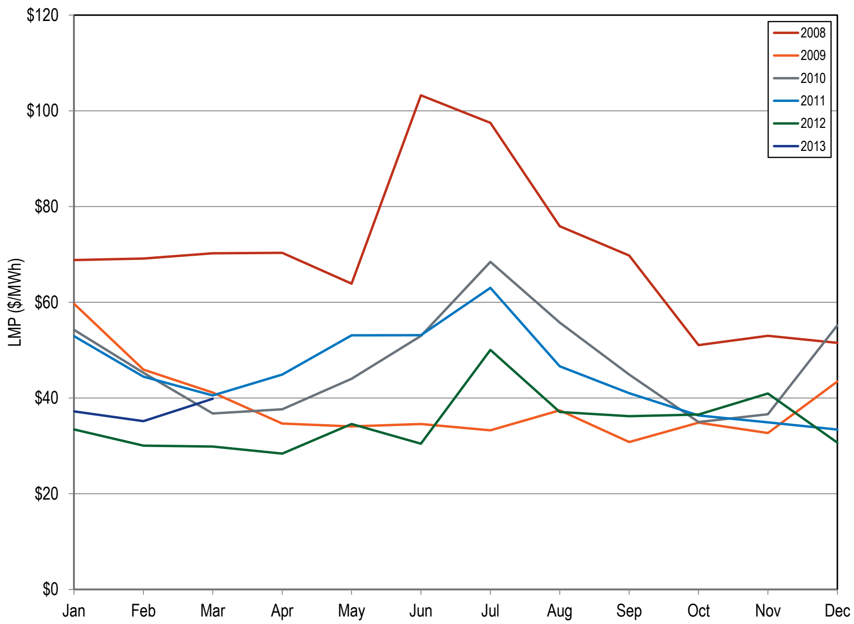
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	19.9%	12.1%	65.7%

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

Figure 2-18 shows the PJM real-time, monthly, load-weighted LMP from 2008 through the first three months of 2013.

46 The system 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.

Figure 2-18 PJM real-time, monthly, load-weighted, average LMP: January 2008 through March of 2013



Fuel Price Trends and 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. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas, especially in the eastern part of PJM increased in price in the first three months of 2013. Comparing prices in the first three months of 2013 to prices in 2012, the price of Northern Appalachian coal was 2.1 percent lower; the price of Central Appalachian coal was 3.8 percent higher; the price of Powder River Basin coal was 16.5 percent higher; the price of eastern natural gas was 72.2 percent higher; and the price of western natural gas was 28.0 percent higher. Figure 2-19 shows monthly average spot fuel prices for 2012 and the first three months of 2013.[47] Natural gas prices were above coal prices in the first three months of 2013, with prices above $10/MMBtu for some days. Coal prices decreased during the first three months of 2013 but remained relatively flat in comparison to 2012.

Figure 2-19 Spot average fuel price comparison: 2012 and January through March 2013 ($/MMBtu)

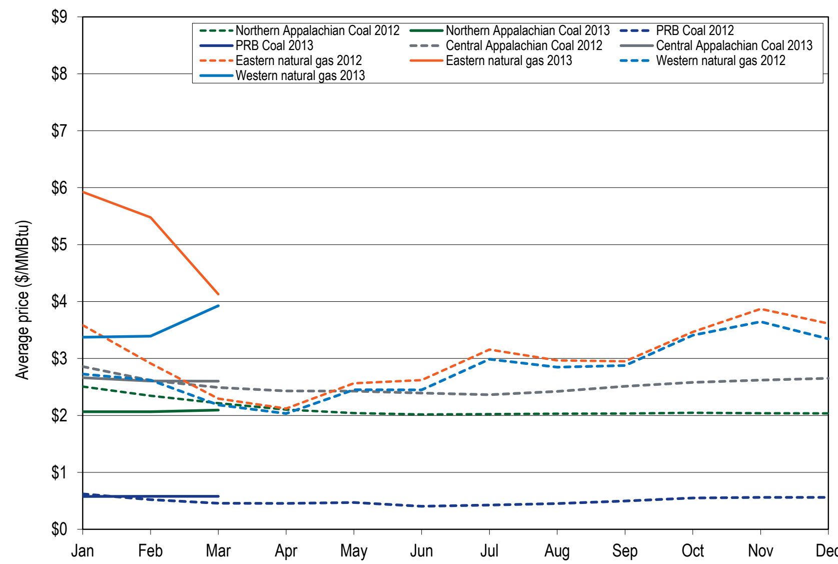


Figure 2-20 shows the average cost of generation, comparing the cost of energy generated by a coal plant, a combined cycle, and a combustion turbine in dollars per MWh. The cost of a new entrant combined cycle was below the cost of a new entrant coal plant for the first three months of 2013. The average spot fuel cost of a new entrant combined cycle unit was $36.83/MWh, higher than the spot fuel cost of a new entrant coal plant, $19.19/MWh, in 2012.

47 Eastern natural gas and Western natural gas 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.

In the market, new combined cycles are competing with older coal plants. Most coal plants in PJM are 20 years or older, with heat rates greater than a new coal plant. Using average heat rates for existing sub-critical coal units, as well as delivery adders and variable operations and maintenance adders, the average cost of a sub-critical coal unit in PJM in the first three months of 2013 was $31.06, compared to $38.40 for a new entrant combined cycle in the eastern zones. In March, due to lower natural gas prices and slightly higher coal prices, the cost of a new entrant combined cycle unit was $30.93, or below that of a sub-critical coal unit in PJM, at $31.26.

Figure 2-20 Average spot fuel cost of generation of CP, CT, CC, and PJM average heat rate sub-critical coal plant: 2012 and January through March 2013 ($/MWh)

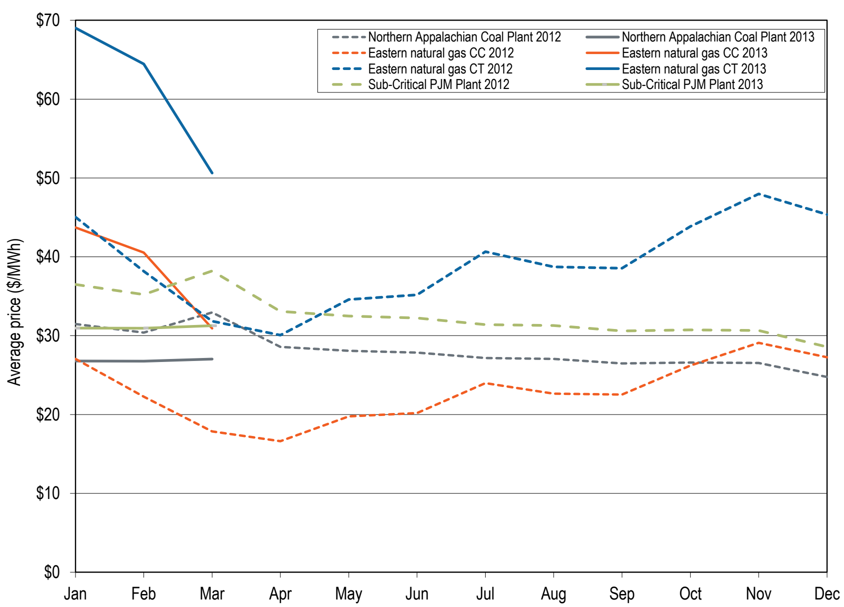


Table 2-38 compares the first three months of 2013 PJM real-time fuel cost adjusted, load weighted, average LMP to the first three months of 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for the first three months of 2013 was 9.8 percent lower than the load weighted, average LMP for the first three months of 2013. The real-time, fuel cost adjusted, load weighted, average LMP for the first three months of 2013 was 8.1 percent higher than the load weighted LMP for the first three months of 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $33.74 per MWh instead of the observed $37.41 per MWh. The mix of fuel types and fuel costs in 2013 resulted in slightly higher prices in 2013 than would have occurred if fuel prices had remained at their 2012 levels.

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

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$37.41	$33.74	(9.8%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$31.21	$33.74	8.1%
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$31.21	$37.41	19.9%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five-minute-ahead forecast of the system conditions. 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's load-weighted 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. 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.[48]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the interval's most recent SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. Occasionally, generators providing energy have to be redispatched lower to increase reserves for meeting ancillary service requirements. The cooptimization of energy and reserves takes into account the lost opportunity cost of lowered generation and the incremental cost to maintain reserves, which are reflected in higher LMPs. The cost of substituting energy for reserve and regulation is shown as Ancillary Service Redispatch Cost. Occasionally, an abrupt loss of generation triggers the need for substituting energy for reserve and consequently higher prices.

The components of LMP are shown in Table 2-39, including markup using unadjusted cost offers.[49] (Numbers in parentheses in the table are negative.) Table 2-39 shows that for the first three months of 2013, 53.7 percent of the load-weighted LMP was the result of coal costs, 30.3 percent was the result of gas costs and 0.52 percent was the result of the cost of emission allowances. Markup was -$2.69 per MWh. In the first three months of 2012, 66.7 percent of the load-weighted LMP was the result of coal costs, 20.9 percent was the result of gas costs and 0.7 percent was the result of the cost of emission allowances. Markup was -$2.55. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP rather than all of the components of the offers of units burning that fuel.

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

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

Table 2-39 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through March 2013 and 2012

	2012 (Jan-Mar)		2013 (Jan-Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$20.83	66.7%	$20.07	53.7%
Gas	$6.51	20.9%	$11.34	30.3%
Ten Percent Addder	$3.36	10.8%	$3.77	10.1%
VOM	$2.34	7.5%	$2.29	6.1%
NA	$0.23	0.7%	$0.68	1.8%
LPA Rounding Difference	$0.22	0.7%	$0.65	1.7%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.38	1.0%
FMU Adder	$0.04	0.1%	$0.37	1.0%
Oil	$0.28	0.9%	$0.30	0.8%
Increase Generation Adder	($0.06)	(0.2%)	$0.15	0.4%
CO_2 Cost	$0.06	0.2%	$0.09	0.2%
NO_x Cost	$0.12	0.4%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.05	0.2%	$0.00	0.0%
Wind	($0.07)	(0.2%)	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.00	0.0%	$0.00	0.0%
Decrease Generation Adder	($0.17)	(0.5%)	($0.10)	(0.3%)
LPA-SCED Differential	($0.01)	(0.0%)	$0.00	0.0%
Markup	($2.55)	(8.2%)	($2.69)	(7.2%)
Total	$31.21	100.0%	$37.41	100.0%

All generating units, including coal units, are allowed to include a ten percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 2-39 and Table 2-43), markup is simply the difference between the price offer and the cost offer. In the second approach

(Table 2-40 and Table 2-44), the 10 percent markup is removed from the cost offers of coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. Actual participant behavior support this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

The components of LMP are shown in Table 2-40, including markup using adjusted cost offers.

Table 2-40 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through March 2013 and 2012

	2012 (Jan-Mar)		2013 (Jan-Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$21.01	67.3%	$20.31	54.3%
Gas	$6.51	20.9%	$11.35	30.3%
VOM	$2.36	7.5%	$2.31	6.2%
Ten Percent Adder	$1.12	3.6%	$1.88	5.0%
NA	$0.23	0.7%	$0.65	1.7%
LPA Rounding Difference	$0.22	0.7%	$0.65	1.7%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.38	1.0%
Oil	$0.28	0.9%	$0.30	0.8%
FMU Adder	$0.04	0.1%	$0.27	0.7%
Increase Generation Adder	($0.06)	(0.2%)	$0.15	0.4%
CO_2 Cost	$0.06	0.2%	$0.09	0.3%
NO_x Cost	$0.12	0.4%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.05	0.2%	$0.00	0.0%
Wind	($0.07)	(0.2%)	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.00	0.0%	$0.00	0.0%
Decrease Generation Adder	($0.17)	(0.5%)	($0.10)	(0.3%)
LPA-SCED Differential	($0.01)	(0.0%)	$0.00	0.0%
Markup	($0.51)	(1.6%)	($0.95)	(2.5%)
Total	$31.21	100.0%	$37.41	100.0%

Day-Ahead LMP

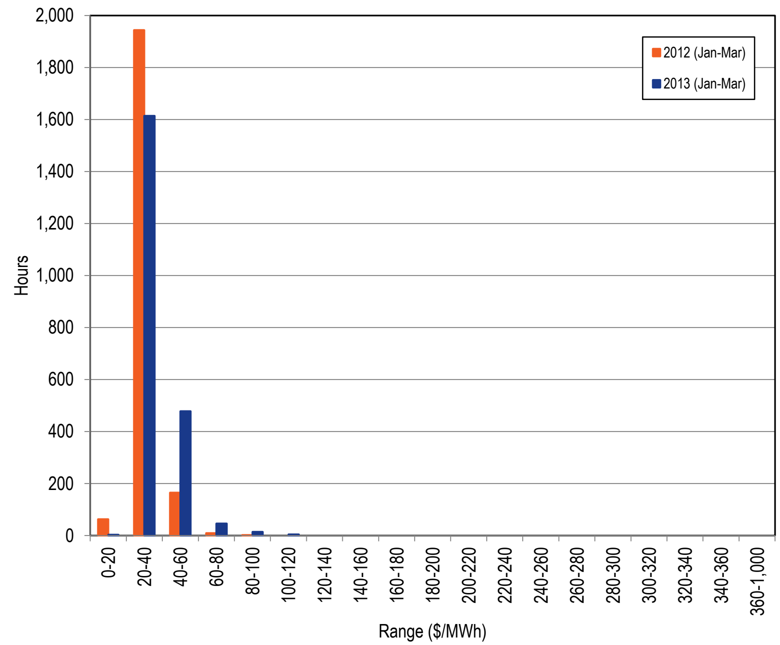
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[50] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-21 shows the hourly distribution of PJM day-ahead average LMP for the first three months of 2012 and 2013.

Figure 2-21 Price for the PJM Day-Ahead Energy Market: January through March of 2012 and 2013



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

PJM Day-Ahead, Average LMP

Table 2-41 shows the PJM day-ahead, average LMP for the first three months of the 13-year period 2001 to 2013.

Table 2-41 PJM day-ahead, average LMP (Dollars per MWh): January through March of 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	18.3%	14.7%	47.5%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. 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, Load-Weighted, Average LMP

Table 2-42 shows the PJM day-ahead, load-weighted, average LMP for the first three months of the 13-year period 2001 to 2013.

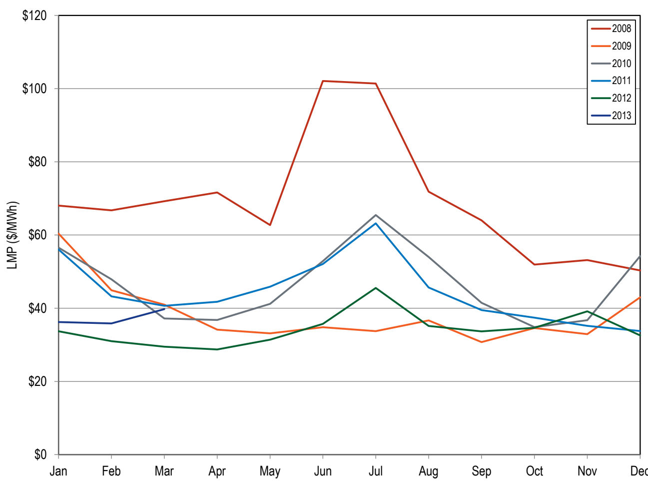
Table 2-42 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March of 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	18.3%	15.0%	50.3%

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

Figure 2-22 shows the PJM day-ahead, monthly, load-weighted LMP from 2008 through the first three months of 2013.

Figure 2-22 Day-ahead, monthly, load-weighted, average LMP: January 2008 through March of 2013



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 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 up-to congestion transactions are dispatchable injections and withdrawals in the Day Ahead market. To the extent that INCs, DECs or up-to congestion 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.

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.[51]

Table 2-43 shows the components of the PJM day ahead, annual, load-weighted average LMP.

Table 2-43 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March 2012 and 2013[52]

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$14.73	46.8%	$15.47	41.5%
Gas	$5.77	18.3%	$5.57	14.9%
DEC	$4.02	12.8%	$7.20	19.3%
INC	$3.33	10.6%	$3.23	8.7%
Up-to Congestion Transaction	$2.05	6.5%	$2.45	6.6%
10% Cost Adder	$1.50	4.8%	$1.68	4.5%
VOM	$1.12	3.6%	$3.07	8.2%
Dispatchable Transaction	$0.88	2.8%	$0.18	0.5%
Price Sensitive Demand	$0.55	1.8%	$0.43	1.2%
FMU Adder	$0.13	0.4%	$0.01	0.0%
CO_2	$0.08	0.3%	$0.06	0.2%
NO_x	$0.03	0.1%	$0.07	0.2%
Oil	$0.02	0.1%	$0.01	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
DASR LOC Adder	($0.00)	(0.0%)	$0.00	0.0%
DASR Offer Adder	($2.70)	(8.6%)	($2.74)	(7.4%)
Markup	$0.00	0.0%	$0.13	0.4%
NA	($0.00)	(0.0%)	$0.43	1.2%
Total	$31.51	100.0%	$37.26	100.0%

Table 2-44 shows the components of the PJM day ahead, annual, load-weighted average LMP.

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

52 The NA in 2013 is $0.43. It is caused by bad savecase input files for March 5, 2013.

Table 2-44 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$14.73	46.8%	$15.47	41.5%
Gas	$5.77	18.3%	$5.57	14.9%
DEC	$4.02	12.8%	$7.20	19.3%
INC	$3.33	10.6%	$3.23	8.7%
Up-to Congestion Transaction	$1.50	4.8%	$1.68	4.5%
VOM	$1.12	3.6%	$3.07	8.2%
10% Cost Adder	$0.88	2.8%	$0.18	0.5%
Dispatchable Transaction	$0.87	2.7%	$1.60	4.3%
Price Sensitive Demand	$0.55	1.8%	$0.43	1.2%
FMU Adder	$0.13	0.4%	$0.01	0.0%
CO_2	$0.08	0.3%	$0.06	0.2%
NO_x	$0.03	0.1%	$0.07	0.2%
Oil	$0.02	0.1%	$0.01	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
DASR LOC Adder	($0.00)	(0.0%)	$0.00	0.0%
DASR Offer Adder	($1.51)	(4.8%)	($1.89)	(5.1%)
Markup	$0.00	0.0%	$0.13	0.4%
NA	($0.00)	(0.0%)	$0.43	1.2%
Total	$31.51	100.0%	$37.26	100.0%

Virtual Offers and Bids

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.[53]

53 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. Internal up-to congestion transactions may source or sink at any of the eligible hubs, transmission zones, aggregates, or single buses for which LMP is calculated. For a complete list of eligible locations for up-to congestion source and sink transactions see the following link from the PJM website: <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 2-23 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 March 2013.

Figure 2-23 PJM day-ahead aggregate supply curves: 2013 example day

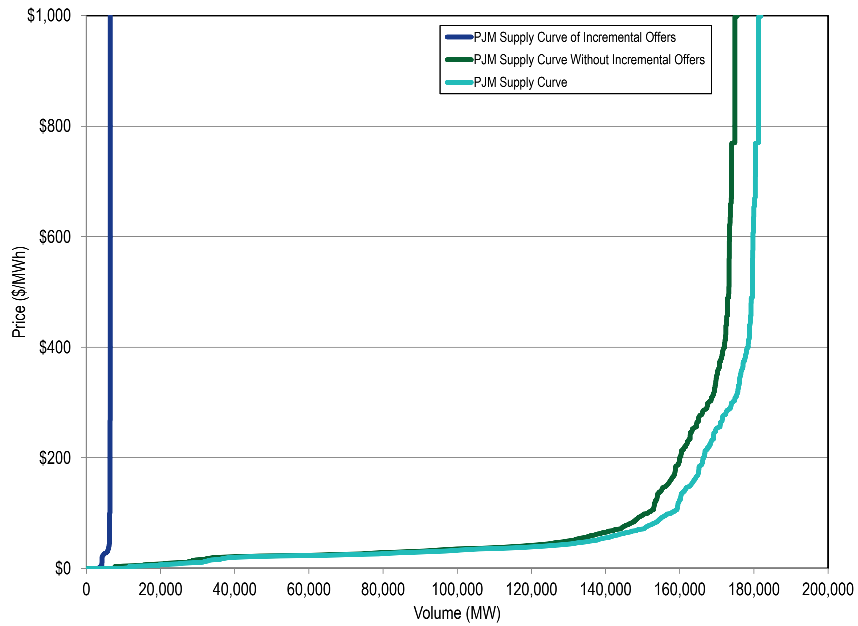


Table 2-45 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour for 2012 through the first three months of 2013. Table 2-46 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour for 2012 through the first three months of 2013. In the first three months of 2013, the average submitted and cleared increment bid MW decreased 31.7 and 11.1 percent, and the average submitted and cleared decrement bid MW decreased 22.6 and 5.6 percent, compared to the first three months of 2012. In the first three months of 2013, average up-to congestion submitted MW increased 47.5 percent and cleared MW increased 26.8 percent, compared to the first three months of 2012. The increase in up-to congestion transactions displaced increment and decrement transactions.

Table 2-45 Hourly average volume of cleared and submitted INCs, DECs by month: January 2012 through March of 2013

		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
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012	Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012	Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012	Annual	6,001	8,428	81	311	8,431	11,089	105	343
2013	Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013	Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013	Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013	Annual	5,682	6,903	63	140	7,507	8,834	74	172

Table 2-46 Hourly average of cleared and submitted up-to congestion bids by month: January 2012 through March 2013

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Apr	43,777	120,955	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,499	143,853	1,329	3,934
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,343	119,744	1,033	2,801
2013	Jan	44,844	157,229	883	4,205
2013	Feb	46,351	144,066	893	3,862
2013	Mar	48,937	162,958	853	3,740
2013	Annual	46,711	154,751	876	3,936

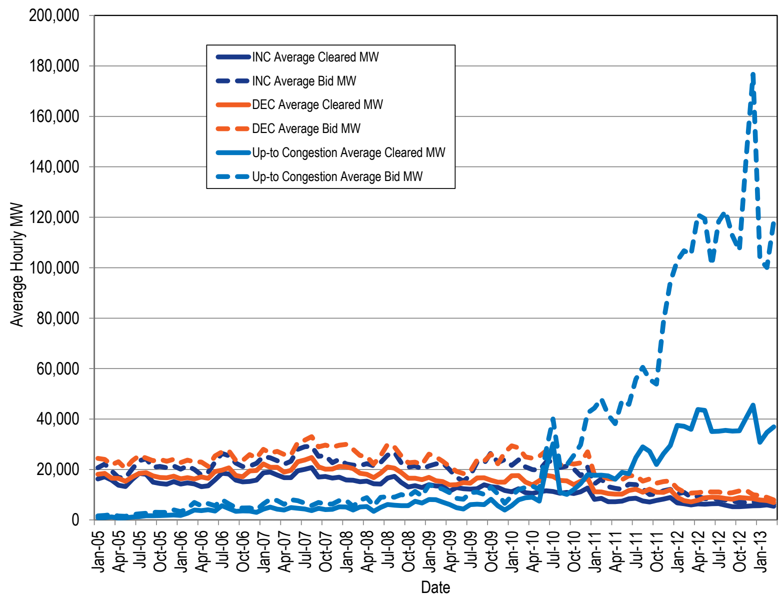
Table 2-47 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.[54]

Table 2-47 Type of day-ahead marginal units: January through March 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.0%	0.1%	93.5%	2.0%	1.4%	0.0%
Feb	2.6%	0.1%	94.6%	1.3%	1.4%	0.0%
Mar	1.6%	0.1%	97.3%	0.5%	0.5%	0.0%
Annual	2.3%	0.1%	95.4%	1.2%	1.0%	0.0%

Figure 2-24 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-24 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through March, 2013



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 2-48 shows, for the first three months of 2012 and 2013, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-49 shows for the first three months of 2012 and 2013, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion bids are financial and account for 63.6 percent of all the cleared up-to congestion MW in PJM in the first three months of 2013.

Table 2-48 PJM INC and DEC bids by type of parent organization (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	17,440,367	37.1%	7,803,420	23.0%
Physical	29,532,769	62.9%	26,141,745	77.0%
Total	46,973,136	100.0%	33,945,165	100.0%

Table 2-49 PJM up-to congestion transactions by type of parent organization (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	76,514,461	95.1%	94,709,907	93.8%
Physical	3,931,378	4.9%	6,211,701	6.2%
Total	80,445,839	100.0%	100,921,609	100.0%

54 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 2-50 shows increment offers and decrement bids bid by top ten locations for the first three months of 2012 and 2013.

Table 2-50 PJM virtual offers and bids by top ten locations (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)					2013 (Jan - Mar)			
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	7,688,302	8,954,480	16,642,782	WESTERN HUB	HUB	6,709,062	7,469,243	14,178,305
AEP-DAYTON HUB	HUB	1,311,830	1,322,353	2,634,183	SOUTHIMP	INTERFACE	2,451,598	0	2,451,598
SOUTHIMP	INTERFACE	2,362,472	0	2,362,472	N ILLINOIS HUB	HUB	601,071	1,406,425	2,007,496
N ILLINOIS HUB	HUB	797,387	1,217,638	2,015,025	AEP-DAYTON HUB	HUB	855,706	915,790	1,771,496
PECO	ZONE	569,142	1,413,636	1,982,778	IMO	INTERFACE	1,415,648	26,744	1,442,392
PPL	ZONE	109,230	1,461,786	1,571,016	PPL	ZONE	21,829	1,416,128	1,437,957
MISO	INTERFACE	68,763	1,325,083	1,393,845	PECO	ZONE	37,216	850,576	887,793
IMO	INTERFACE	1,095,465	7,054	1,102,519	NYIS	INTERFACE	74,855	589,255	664,110
PSEG	ZONE	211,672	342,435	554,107	MISO	INTERFACE	53,127	535,276	588,403
BGE	ZONE	53,894	446,806	500,700	DOMINION HUB	HUB	99,832	370,797	470,629
Top ten total		14,268,157	16,491,270	30,759,427			12,319,944	13,580,235	25,900,179
PJM total		22,025,564	24,947,572	46,973,136			14,879,528	19,065,637	33,945,165
Top ten total as percent of PJM total		64.8%	66.1%	65.5%			82.8%	71.2%	76.3%

Table 2-51 shows up-to congestion transactions by import bids for the top ten locations for the first three months of 2012 and 2013.[55]

Table 2-52 shows up-to congestion transactions by export bids for the top ten locations for the first three months of 2012 and 2013.

Table 2-51 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	3,950,243
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,372,477
OVEC	INTERFACE	DEOK	ZONE	1,064,356
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	752,791
MISO	INTERFACE	N ILLINOIS HUB	HUB	724,225
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	701,270
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	616,066
MISO	INTERFACE	POWERTON 5	AGGREGATE	615,189
NYIS	INTERFACE	HUDSON BC	AGGREGATE	523,487
MISO	INTERFACE	COOK	EHVAGG	418,931
Top ten total				10,739,036
PJM total				39,854,575
Top ten total as percent of PJM total				26.9%
2013 (Jan - Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
NYIS	INTERFACE	HUDSON BC	AGGREGATE	403,639
OVEC	INTERFACE	DEOK	ZONE	381,127
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	311,221
OVEC	INTERFACE	STUART 1	AGGREGATE	243,555
MISO	INTERFACE	112 WILTON	EHVAGG	236,497
OVEC	INTERFACE	ZIMMER	AGGREGATE	219,178
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	191,405
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	173,209
OVEC	INTERFACE	OHIO HUB	HUB	172,597
OVEC	INTERFACE	STUART 4	AGGREGATE	170,534
Top ten total				2,502,961
PJM total				11,003,102
Top ten total as percent of PJM total				22.7%

Table 2-52 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	OVEC	INTERFACE	1,653,313
ROCKPORT	EHVAGG	SOUTHWEST	AGGREGATE	1,079,308
23 COLLINS	EHVAGG	MISO	INTERFACE	931,276
167 PLANO	EHVAGG	MISO	INTERFACE	757,345
SPORN 3	AGGREGATE	OVEC	INTERFACE	646,956
WESTERN HUB	HUB	MISO	INTERFACE	633,292
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	570,882
ROCKPORT	EHVAGG	MISO	INTERFACE	544,717
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	536,568
SPORN 5	AGGREGATE	OVEC	INTERFACE	530,900
Top ten total				7,884,555
PJM total				40,363,681
Top ten total as percent of PJM total				19.5%
2013 (Jan - Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
GAVIN	EHVAGG	OVEC	INTERFACE	440,608
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	368,347
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	350,741
SPORN 3	AGGREGATE	OVEC	INTERFACE	293,548
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	253,264
JEFFERSON	EHVAGG	OVEC	INTERFACE	249,922
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	194,734
CULLODEN	EHVAGG	OVEC	INTERFACE	188,867
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	182,977
BIG SANDY CT4	AGGREGATE	SOUTHWEST	INTERFACE	166,899
Top ten total				2,689,906
PJM total				14,919,573
Top ten total as percent of PJM total				18.0%

55 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 2-53 shows up-to congestion transactions by wheel bids for the top ten locations for the first three months of 2012 and 2013.

Table 2-53 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	50,943
NIPSCO	INTERFACE	NORTHWEST	INTERFACE	18,738
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	13,961
NORTHWEST	INTERFACE	MISO	INTERFACE	13,833
SOUTHEAST	AGGREGATE	SOUTHWEST	AGGREGATE	11,601
SOUTHWEST	AGGREGATE	SOUTHEXP	INTERFACE	10,572
OVEC	INTERFACE	SOUTHEXP	INTERFACE	9,346
NYIS	INTERFACE	NEPTUNE	INTERFACE	8,786
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	8,593
NIPSCO	INTERFACE	IMO	INTERFACE	7,855
Top ten total				154,227
PJM total				227,583
Top ten total as percent of PJM total				67.8%
2013 (Jan - Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	438,456
IMO	INTERFACE	NYIS	INTERFACE	198,859
MISO	INTERFACE	NIPSCO	INTERFACE	133,002
LINDENVFT	INTERFACE	NYIS	INTERFACE	76,636
MISO	INTERFACE	SOUTHEXP	INTERFACE	53,205
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	51,723
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	41,180
NORTHWEST	INTERFACE	MISO	INTERFACE	40,196
MISO	INTERFACE	OVEC	INTERFACE	33,088
NYIS	INTERFACE	LINDENVFT	INTERFACE	27,935
Top ten total				1,094,280
PJM total				1,342,254
Top ten total as percent of PJM total				81.5%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[56] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 8.0 percent of the PJM total internal up-to congestion transactions in the first three months of 2013.

56 For more information, see the *2012 State of the Market Report for PJM* Section 8, "Interchange Transactions," Up-to Congestion.

Table 2-54 shows up-to congestion transactions by internal bids for the top ten locations for the first three months of 2013.

Table 2-54 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through March of 2013

2013 (Jan - Mar)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	1,298,253
YADKIN	EHVAGG	FENTRESS	EHVAGG	763,731
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	600,547
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	563,064
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	501,756
BROADFORD	EHVAGG	CLINCH RIVER 1	AGGREGATE	487,787
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	487,593
DELI	AGGREGATE	BYRON 1	AGGREGATE	461,131
GENEVA	AGGREGATE	WINNETKA	AGGREGATE	377,375
NAPERVILLE	AGGREGATE	CHICAGO HUB	HUB	358,100
Top ten total				5,899,339
PJM total				73,656,680
Top ten total as percent of PJM total				8.0%

Table 2-55 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and the first three months of 2013. The increase in average offered and cleared source-sink pairs in November and December of 2012 and the first three months of 2013 illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions. The increase in source-sink pairs available for up-to congestion transactions has also led to more dispersion in the number of cleared up-to congestion transaction internal bids by location.

Table 2-55 Number of PJM offered and cleared source and sink pairs: January 2012 through March of 2013

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,818	3,951	1,796	2,709
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Annual	5,443	8,470	2,972	4,410

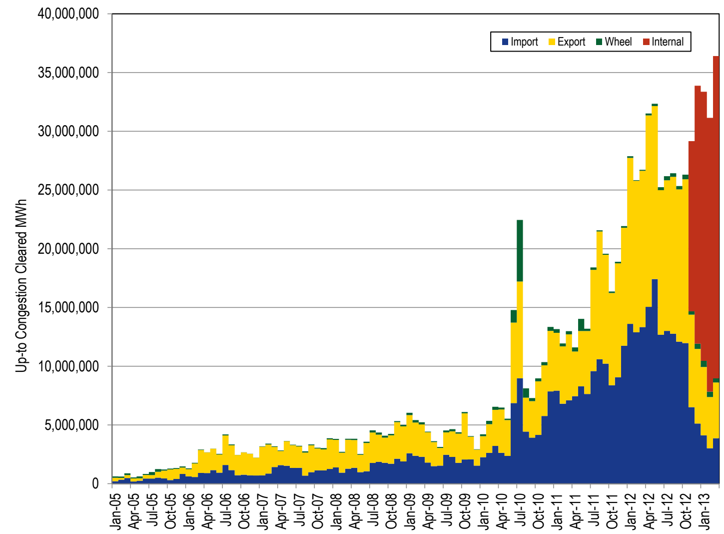
Table 2-56 PJM cleared up-to congestion transactions by type (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,739,036	7,884,555	154,227	NA	12,986,604
PJM total (MW)	39,854,575	40,363,681	227,583	NA	80,445,839
Top ten total as percent of PJM total	26.9%	19.5%	67.8%	NA	16.1%
PJM total as percent of all up-to congestion transactions	49.5%	50.2%	0.3%	NA	100.0%
	2013 (Jan - Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,502,961	2,689,906	1,094,280	5,899,339	6,042,928
PJM total (MW)	11,003,102	14,919,573	1,342,254	73,656,680	100,921,609
Top ten total as percent of PJM total	22.7%	18.0%	81.5%	8.0%	6.0%
PJM total as percent of all up-to congestion transactions	10.9%	14.8%	1.3%	73.0%	100.0%

Table 2-56 and Figure 2-25 show total cleared up-to congestion transactions by type for the first three months of 2012 and 2013. Internal up-to congestion transactions in the first three months of 2013 were 73.0 percent of all up-to congestion transactions for the first three months of 2013.

Figure 2-25 shows the spike in internal up-to congestion transactions in November and December of 2012 and the first three months of 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 2-25 PJM cleared up-to congestion transactions by type (MW): January 2005 through March of 2013



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. Convergence is not the goal of virtual trading but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Market. 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 to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-27).

Table 2-57 shows, day-ahead and real-time prices were relatively close, on average, in the first three months of 2012 and 2013.

Table 2-57 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2012 and 2013[57]

	2012 (Jan - Mar)				2013 (Jan - Mar)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$30.82	$30.38	($0.43)	(1.4%)	$36.46	$36.33	($0.13)	(0.4%)
Median	$30.04	$28.82	($1.22)	(4.2%)	$34.45	$32.29	($2.16)	(6.7%)
Standard deviation	$6.63	$11.63	$5.00	43.0%	$9.78	$18.47	$8.69	47.0%
Peak average	$33.78	$33.75	($0.03)	(0.1%)	$40.55	$41.02	$0.47	1.1%
Peak median	$32.08	$30.65	($1.43)	(4.7%)	$37.86	$35.02	($2.84)	(8.1%)
Peak standard deviation	$6.30	$12.05	$5.75	47.7%	$10.81	$22.56	$11.75	52.1%
Off peak average	$28.19	$27.41	($0.79)	(2.9%)	$32.87	$32.22	($0.65)	(2.0%)
Off peak median	$27.75	$26.75	($1.00)	(3.7%)	$31.64	$29.82	($1.82)	(6.1%)
Off peak standard deviation	$5.76	$10.38	$4.62	44.5%	$7.05	$12.59	$5.54	44.0%

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

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 as well as conditions in real time that are difficult or impossible to predict.

Table 2-58 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first three months of the 13-year period 2001 to 2013.

Table 2-58 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2001 through 2013

(Jan - Mar)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)
2013	$36.46	$36.33	($0.13)	(0.4%)

Table 2-59 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first three months of the years 2007 through 2013.

Table 2-59 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through March of 2007 through 2013

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	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%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%	0	0.00%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%	0	0.00%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%	1,542	71.42%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%	587	98.61%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%	23	99.68%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%	3	99.81%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%	3	99.95%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	100.00%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-26 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first three months of 2013.

Figure 2-26 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March of 2013

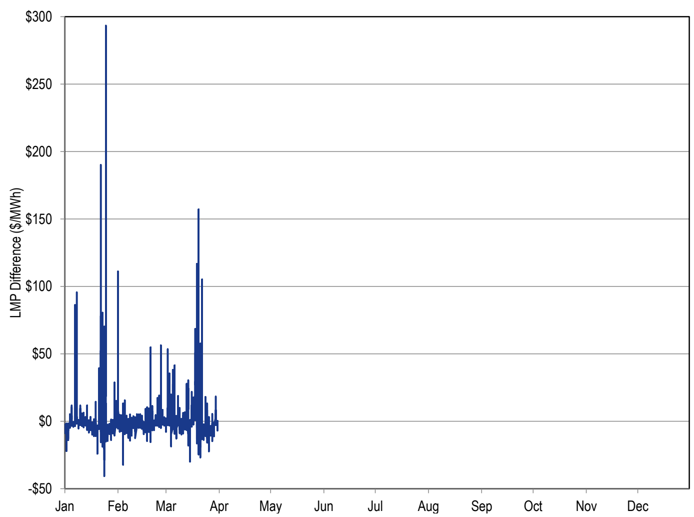


Figure 2-27 shows the monthly average differences between the day-ahead and real-time LMP in the first three months of 2013.

Figure 2-27 Monthly average of real-time minus day-ahead LMP: January through March of 2013

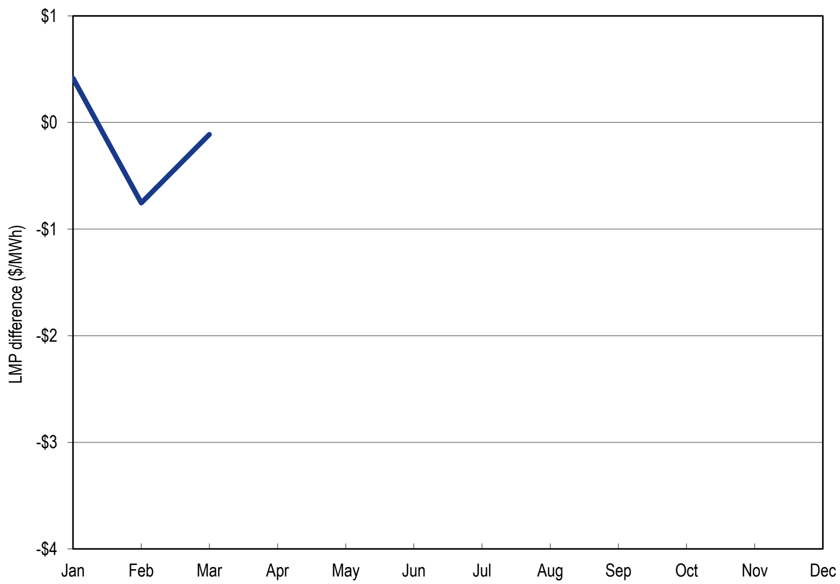
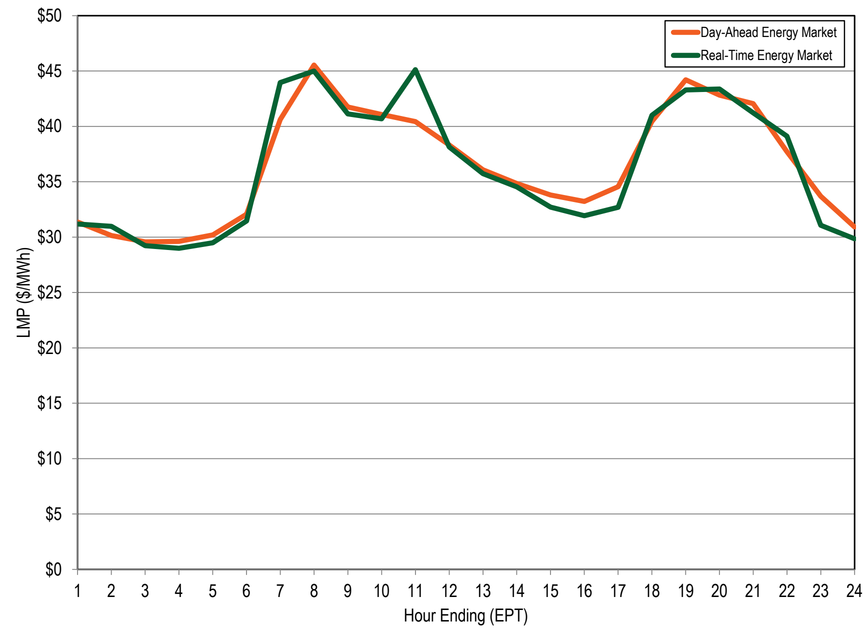


Figure 2-28 shows day-ahead and real-time LMP on an average hourly basis for the first three months of 2013.

Figure 2-28 PJM system hourly average LMP: January through March of 2013



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 2-60 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2012 and 2013 based on parent company. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points.

Table 2-60 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%						
May	8.6%	23.5%	67.9%						
Jun	8.7%	22.3%	69.0%						
Jul	8.0%	22.7%	69.3%						
Aug	8.5%	23.6%	67.9%						
Sep	9.1%	24.4%	66.5%						
Oct	9.6%	25.5%	64.9%						
Nov	9.9%	23.9%	66.3%						
Dec	10.2%	22.6%	67.3%						
Annual	9.0%	23.2%	67.8%	10.5%	22.8%	66.8%	1.4%	(0.4%)	(1.0%)

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 2-61 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2011 and 2012, based on parent companies. For the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

Table 2-61 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%						
May	6.6%	22.7%	70.7%						
Jun	7.7%	20.7%	71.6%						
Jul	5.9%	22.0%	72.0%						
Aug	6.4%	22.5%	71.0%						
Sep	6.5%	23.9%	69.6%						
Oct	6.6%	25.2%	68.2%						
Nov	6.9%	22.7%	70.5%						
Dec	7.0%	21.2%	71.8%						
Annual	6.7%	22.3%	71.0%	6.9%	22.6%	70.5%	0.2%	0.3%	(0.5%)

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.[1] 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 increased by 111.8 percent in the first three months of 2013 compared to the first three months of 2012, to a total of $260.2 million. Total operating reserve charges in the first three months of 2013 were $260.2 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 9.0 percent, the balancing operating reserve charges proportion was 61.1 percent, the reactive services charges proportion was 21.4 percent, the synchronous condensing charges proportion was 0.001 percent and the black start services charges proportion was 8.5 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.082 per MWh, the day-ahead operating reserve rate including unallocated congestion charges averaged $0.114 per MWh, the balancing operating reserve reliability rates averaged $0.058, $0.065 and $0.003 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $1.001, $5.967 and $0.055 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $0.655 per MWh and canceled resources rate averaged $0.0002 per MWh.

1 See the *2012 State of the Market Report for PJM, Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 99-103 for a full description of how operating reserve credits and charges are calculated.

Characteristics of Credits

- **Types of units.** Combined cycles received 52.6 percent of all day-ahead generator credits and 69.2 percent of all balancing generator credits. Combustion turbines and diesels received 77.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 88.7 percent of all reactive services credits.
- **Economic – Noneconomic Generation.** In the first three months of 2013, 82.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.3 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first three months of 2013, 79.7 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.3 percent by transactions at hubs and 14.0 percent by transactions at interfaces.
- Generators in the Eastern Region paid 17.4 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 87.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 14.7 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 12.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators paid 13.7 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.99 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 48.6 percent of all credits. The top 10 organizations received 90.8 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 5372, balancing operating reserves was 5291 and lost opportunity cost HHI was 5418.

- **Day-Ahead Unit Commitment for Reliability:** In the first three months of 2013, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, of which, 67.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first three months of 2013, lost opportunity cost credits decreased by $1.2 million compared to the first three months of 2012. In the first three months of 2013, the top three control zones receiving lost opportunity cost credits, ATSI, AP and ComEd combined for 70.3 percent of all lost opportunity cost credits, 54.0 percent of all the day-ahead generation from pool-scheduled combustion turbines and diesels, 73.4 percent of all day-ahead generation not called in real time by PJM from those unit types and 82.0 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Lost Opportunity Cost Calculation:** In the first three months of 2013, lost opportunity cost credits would have been reduced by $6.7 million, or 34.0 percent, if all changes proposed by the MMU had been implemented.
- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running even if not economic. In the first three months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $22.2 million.
- **Con Edison – PSEG Wheeling Contracts Support:** 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.
- **Up-to Congestion Transactions:** Up-to congestion transactions do not pay operating reserve charges despite that they affect dispatch and commitment in the Day-Ahead Energy Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant. For example, in the first three months of 2013, the RTO deviation rate would have been reduced by 74.7 percent if up-to congestion transactions had been included in the calculation of operating reserve charges.

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 goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

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, the details of the rules which define payments 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, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[2] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

Overall, the MMU recommends that the goal be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred operating reserve charges and to increase the transactions over which those charges are spread in order to reduce the impact of operating reserve charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

New Operating Reserve Categories

New rules regarding the allocation method for operating reserve make whole payments for reliability purposes became effective on December 1, 2012.[3] The new rules allocate the day-ahead operating reserve charges for units scheduled in day ahead or committed in real time to provide black start services consistently with Schedule 6A of the tariff.[4] The new rules also allocate the day-ahead operating reserve charges for units scheduled in day-ahead to provide reactive services or transfer interface control zonally, in proportion to the real-time deliveries of energy to load.

Black Start Services

Black start services credits are paid in the form of day-ahead operating reserve credits or balancing operating reserve credits depending on whether the unit was scheduled in day ahead or committed in real time to provide black start service. These credits consist of make whole payments to units capable of providing black start services.[5]

The black start services charges that result from paying day-ahead and balancing operating reserve credits to units providing black start services

2 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement" for PJM's MRC April 25, 2013 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

3 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

4 Schedule 6A of the OATT contains the rules governing black start service.

5 Day-ahead and balancing operating reserve credits paid to units providing black start services or performing black start testing are categorized as day-ahead or balancing black start services credits in this report.

or performing black start testing are allocated monthly to PJM members in proportion to their zone and non-zone peak transmission use.[6,7]

Reactive Services

Reactive service credits are paid to units committed in real time for the purpose of maintaining the reactive reliability of the PJM region. Units are paid reactive services credits if such units are reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price or 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 services credits are also paid in the form of day-ahead operating reserve credits to units scheduled in day ahead to provide reactive services in real time. These credits consist of make whole payments to units scheduled in day ahead to maintain the reactive reliability in real time.[8]

The costs of units committed in real time and scheduled in day ahead to maintain the reactive reliability of the PJM region are allocated as reactive services charges. Reactive service charges are allocated daily to real-time load in the transmission zone or zones where the reactive service was provided.[9]

Credits and Charges Categories

Operating reserves include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 and Table 3-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 3-1 Day-ahead and balancing operating reserve credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability Balancing Operating Reserve for Deviations Balancing Local Constraint	Real-Time Load plus Export Transactions Real-Time Deviations from Day-Ahead Schedule Applicable Requesting Party	in RTO, Eastern or Western Region
Canceled Resources Lost Opportunity Cost (LOC) Real-Time Import Transactions Resources Providing Quick Start Reserve	Balancing Operating Reserve Startup Cancellation Balancing Operating Reserve LOC Balancing Operating Reserve Transaction Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	in RTO Region
Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Real-Time Deviations from Day-Ahead Schedule by RTO, Eastern or Western Region	in RTO, Eastern or Western Region

6 Prior December 1, 2012 the costs of units providing black start services and performing black start testing were allocated as day-ahead or balancing operating reserve charges.
7 See OATT Schedule 6A § for the definition of zone and non-zone peak transmission use.
8 Day-ahead operating reserve credits paid to units scheduled to provide reactive services are categorized as day-ahead reactive services credits in this report.
9 After September 13, 2012 and prior to December 1, 2012 the costs of units scheduled in day ahead to provide reactive services were allocated as day-ahead operating reserve charges.

Table 3-2 Reactive services, synchronous condensing and black start services credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge Reactive Services Local Constraint	Zonal Real-Time Load Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone and Non-zone Peak Transmission Use

Operating Reserve Results

Operating Reserve Charges

Table 3-3 shows total operating reserve charges for the first three months of 2012 and 2013.[10] Total operating reserve charges increased by 111.8 percent in the first three months of 2013 compared to the first three months of 2012, to a total of $260.2 million.

Table 3-3 Total operating reserve charges: January through March 2012 and 2013

	Jan - Mar 2012	Jan - Mar 2013	Change	Percentage Change
Total Operating Reserve Charges	$122,821,626	$260,154,623	$137,332,997	111.8%
Operating Reserve as a Percent of Total PJM Billing	1.8%	3.4%	1.6%	89.3%

Total operating reserve charges in the first three months of 2013 were $260.2 million, up from the total of $122.8 million in the first three months of 2012. Table 3-4 compares monthly operating reserve charges by category for 2012 and 2013. The increase of 111.8 percent in the first three months of 2013 is comprised of a 29.6 percent increase in day-ahead operating reserve charges, a 94.0 percent increase in balancing operating reserve charges, a 144.0 percent increase in reactive services charges, a 96.0 percent decrease in synchronous condensing charges and $22.2 million of the new black start services charges.

10 Table 3-3 includes all categories of charges as defined in Table 3-1 and Table 3-2 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 current on April 9, 2013.

Table 3-4 Monthly operating reserve charges: 2012 and 2013

	2012						2013					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$8,311,574	$27,341,331	$2,934,337	$27,037	$0	$38,614,279	$11,161,579	$77,529,804	$23,604,234	$1,873	$8,453,397	$120,750,888
Feb	$5,858,308	$24,877,526	$13,108,017	$18,592	$0	$43,862,444	$5,194,848	$65,384,968	$17,615,286	$0	$6,988,632	$95,183,734
Mar	$3,852,873	$29,758,387	$6,731,994	$1,648	$0	$40,344,903	$7,004,925	$16,096,320	$14,350,138	$0	$6,768,618	$44,220,001
Apr	$2,967,302	$34,168,703	$4,521,280	$0	$0	$41,657,285						
May	$7,956,965	$43,761,595	$5,392,428	$0	$0	$57,110,987						
Jun	$6,973,548	$45,706,882	$5,133,009	$0	$0	$57,813,439						
Jul	$11,773,179	$66,592,698	$2,960,922	$0	$0	$81,326,799						
Aug	$8,692,702	$47,664,948	$4,112,186	$0	$0	$60,469,836						
Sep	$28,877,736	$32,811,313	$4,458,891	$24,366	$0	$66,172,306						
Oct	$23,382,961	$26,515,214	$1,253,642	$38,762	$0	$51,190,579						
Nov	$18,077,440	$24,438,035	$120,820	$0	$0	$42,636,296						
Dec	$7,878,203	$27,722,687	$25,282,650	$37,845	$8,384,651	$69,306,036						
Total	$18,022,755	$81,977,245	$22,774,348	$47,278	$0	$122,821,626	$23,361,353	$159,011,092	$55,569,658	$1,873	$22,210,646	$260,154,623
Share of Charges	14.7%	66.7%	18.5%	0.0%	0.0%	100.0%	9.0%	61.1%	21.4%	0.0%	8.5%	100.0%

Table 3-5 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for load response and unallocated congestion charges. Day-ahead operating reserve charges increased 29.6 percent or $5.3 million in the first three months of 2013 compared to the first three months of 2012 as a result of unallocated congestion charges.[11]

Table 3-5 Day-ahead operating reserve charges: January through March 2012 and 2013

Type	Jan - Mar 2012	Jan - Mar 2013	Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Day-Ahead Operating Reserve Charges	$18,022,755	$17,425,457	($597,298)	100.0%	74.6%
Day-Ahead Operating Reserve Charges for Load Response	$0	$0	$0	0.0%	0.0%
Unallocated Congestion Charges	$0	$5,935,896	$5,935,896	0.0%	25.4%
Total	$18,022,755	$23,361,353	$5,338,598	100.0%	100.0%

Table 3-6 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for load response and balancing local constraint charges. In the first three months of 2013, balancing operating reserve deviation charges accounted for 88.5 percent of all balancing operating reserve charges, 18.6 percentage points higher compared to the share in the first three months of 2012.

11 See OATT Attachment K - Appendix § 3.2.3B (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves seven times, totaling $12.9 million, 46.0 percent was charged in the first three months of 2013.

Table 3-6 Balancing operating reserve charges: January through March 2012 and 2013

Type	Jan - Mar 2012	Jan - Mar 2013	Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Balancing Operating Reserve Reliability Charges	$22,377,438	$18,259,050	($4,118,388)	27.3%	11.5%
Balancing Operating Reserve Deviation Charges	$57,239,792	$140,671,606	$83,431,815	69.8%	88.5%
Balancing Operating Reserve Charges for Load Response	$83,009	$873	($82,136)	0.1%	0.0%
Balancing Local Constraint Charges	$2,277,006	$79,563	($2,197,443)	2.8%	0.1%
Total	$81,977,245	$159,011,092	$77,033,847	100.0%	100.0%

Table 3-7 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first three months of 2013, 86.0 percent of all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 26.7 percentage points compared to the share in the first three months of 2012.

Table 3-7 Balancing operating reserve deviation charges: January through March 2012 and 2013

Charge attributable to	Jan - Mar 2012	Jan - Mar 2013	Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Make Whole Payments to Generators and Imports	$33,952,809	$121,000,359	$87,047,550	59.3%	86.0%
Energy Lost Opportunity Cost	$20,871,023	$19,664,029	($1,206,994)	36.5%	14.0%
Canceled Resources	$2,415,960	$7,218	($2,408,742)	4.2%	0.0%
Total	$57,239,792	$140,671,606	$83,431,815	100.0%	100.0%

Table 3-8 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012.

Table 3-8 Additional operating reserve charges: January through March 2012 and 2013

Type	Jan - Mar 2012	Jan - Mar 2013	Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Reactive Services Charges	$22,774,348	$55,569,658	$32,795,310	99.8%	71.4%
Synchronous Condensing Charges	$47,278	$1,873	($45,405)	0.2%	0.0%
Black Start Services Charges	$0	$22,210,646	$22,210,646	0.0%	28.6%
Total	$22,821,626	$77,782,178	$54,960,552	100.0%	100.0%

Table 3-9 and Table 3-10 show the amount and percentages of regional balancing charges allocation for the first three months of 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints and resources providing quick start reserve.

In the first three months of 2013, regional balancing operating reserve charges increased by $79.3 million compared to the first three months of 2012. Balancing operating reserve reliability charges decreased by $4.1 million or 18.4 percent and balancing reserve deviation charges increased by $83.4 million or 145.8 percent. In the first three months of 2013, deviation charges in the Eastern Region increased by $84.3 million compared to the first three months of 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[12,13] The remaining two deviation categories decreased by $0.8 million.

Table 3-9 Regional balancing charges allocation: January through March 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$4,009,931	5.0%	$88,579	0.1%	$17,552,181	22.0%	$21,650,691	27.2%
	Real-Time Exports	$112,694	0.1%	$2,265	0.0%	$611,789	0.8%	$726,747	0.9%
	Total	$4,122,625	5.2%	$90,844	0.1%	$18,163,969	22.8%	$22,377,438	28.1%
Deviation Charges	Demand	$28,091,145	35.3%	$3,620,506	4.5%	$437,614	0.5%	$32,149,265	40.4%
	Supply	$11,306,326	14.2%	$1,347,463	1.7%	$172,663	0.2%	$12,826,452	16.1%
	Generator	$10,955,500	13.8%	$993,479	1.2%	$315,096	0.4%	$12,264,075	15.4%
	Total	$50,352,971	63.2%	$5,961,448	7.5%	$925,373	1.2%	$57,239,792	71.9%
Total Regional Balancing Charges		$54,475,597	68.4%	$6,052,291	7.6%	$19,089,342	24.0%	$79,617,230	100%

Table 3-10 Regional balancing charges allocation: January through March 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$11,428,991	7.2%	$6,088,461	3.8%	$323,720	0.2%	$17,841,173	11.2%
	Real-Time Exports	$239,751	0.2%	$172,908	0.1%	$5,218	0.0%	$417,878	0.3%
	Total	$11,668,742	7.3%	$6,261,369	3.9%	$328,938	0.2%	$18,259,050	11.5%
Deviation Charges	Demand	$29,184,458	18.4%	$55,939,858	35.2%	$425,579	0.3%	$85,549,895	53.8%
	Supply	$8,036,881	5.1%	$15,291,042	9.6%	$107,606	0.1%	$23,435,529	14.7%
	Generator	$12,511,542	7.9%	$18,922,713	11.9%	$251,927	0.2%	$31,686,182	19.9%
	Total	$49,732,882	31.3%	$90,153,613	56.7%	$785,112	0.5%	$140,671,606	88.5%
Total Regional Balancing Charges		$61,401,624	38.6%	$96,414,982	60.7%	$1,114,050	0.7%	$158,930,657	100%

Operating Reserve Rates

Under the operating reserves 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 region. See Table 3-1 for how these charges are allocated.[14]

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for 2012 and the first three months of 2013. The average rate in the first three months of 2013 was $0.082 per MWh, $0.005 per MWh lower than the average in the first three months of 2012. The highest rate occurred on March 24, when the rate reached $0.218 per MWh, 0.3 percent higher than the $0.217 per MWh reached during the first three months of 2012, on February 1. On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market.[15]

Figure 3-1 also shows the weekly weighted average day-ahead operating reserve rates including the congestion charges allocated to day-ahead operating reserves. The average rate in the first three months of 2013, including unallocated congestion charges, was $0.114 per MWh, 38.3 percent higher than the day-ahead operating reserve rate without unallocated congestion charges. The highest day-ahead operating rate including unallocated congestion charges occurred on January 18, when the rate reached $0.283 per MWh, 29.7 percent higher than the highest day-ahead operating reserve rates without unallocated congestion charges.

12 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx.

13 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (MIC) (March 6, 2013) http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx.

14 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost rates and the canceled resources rate to the deviation rate for the RTO region since these three charges are allocated following the same rules.

15 See *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): 2012 and 2013

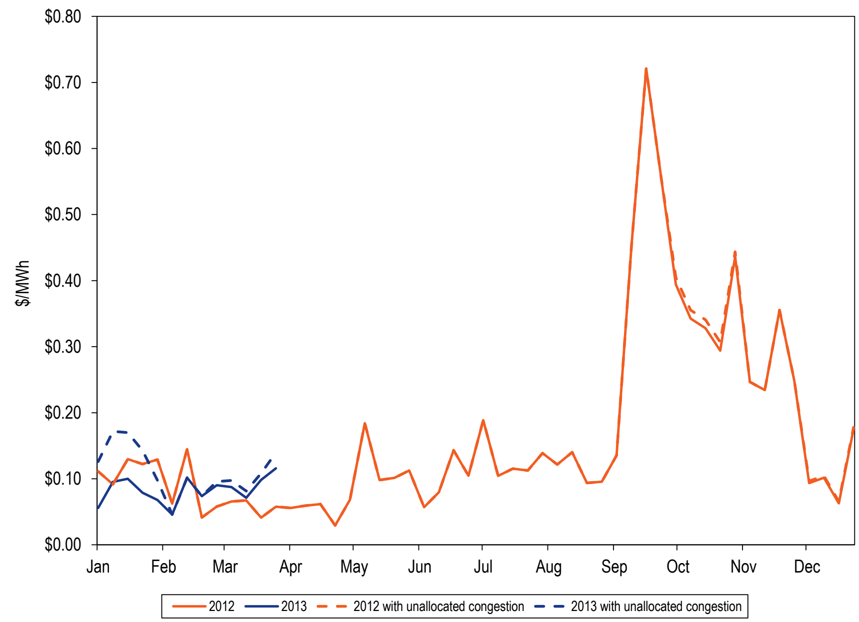


Figure 3-2 shows the RTO and the regional reliability rates for 2012 and the first three months of 2013. The average daily RTO reliability rate was $0.058 per MWh. The highest RTO reliability rate of the first three months of 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.065 per MWh. The highest Eastern Region reliability rate of the first three months of 2013 occurred on January 23, when the rate reached $2.887 per MWh. The spikes on both rates was a result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system in the area which resulted in overloads of the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[16]

Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013

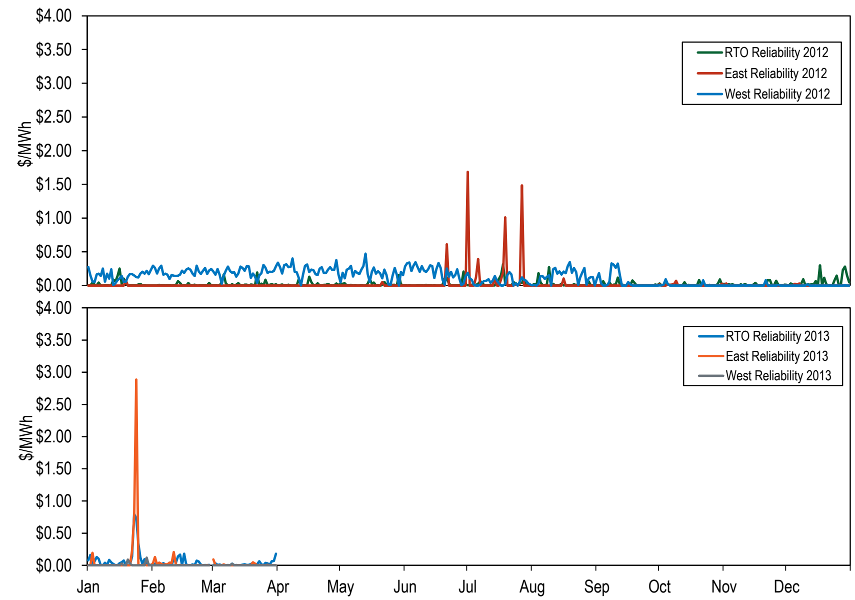


Figure 3-3 shows the RTO and the regional deviation rates for 2012 and the first three months of 2013. The average daily RTO deviation rate was $1.001 per MWh. The highest daily rate in the first three months of 2013 occurred on January 23, when the RTO deviation rate reached $10.155 per MWh. Between January 1 and February 21, 2013, the Eastern Region deviation rate averaged $10.045 per MWh, reaching its highest rate on February 9, when it reached

16 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

$32.767 per MWh, prior to the 2012 – 2013 winter, the highest Eastern Region deviation rate had been $5.739 per MWh. The spikes in the Eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and Eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals).[17]

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

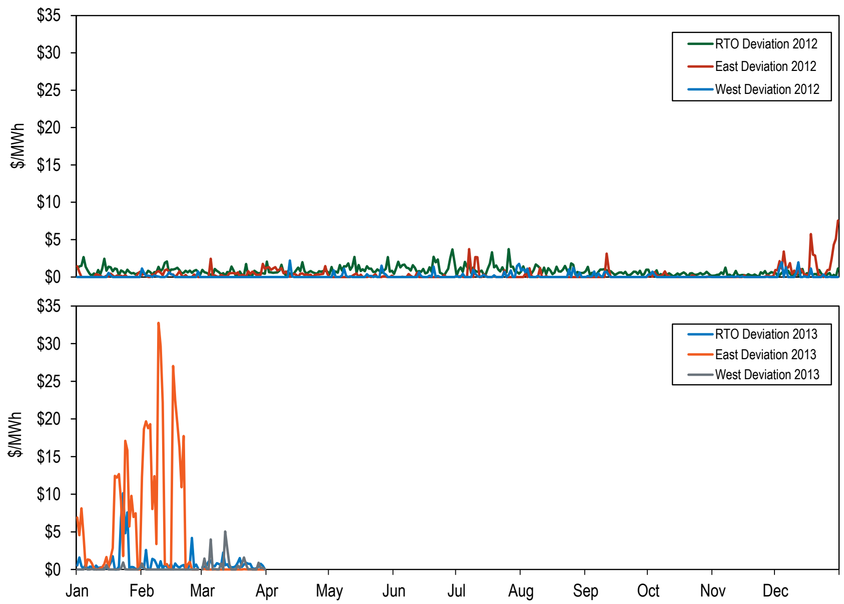
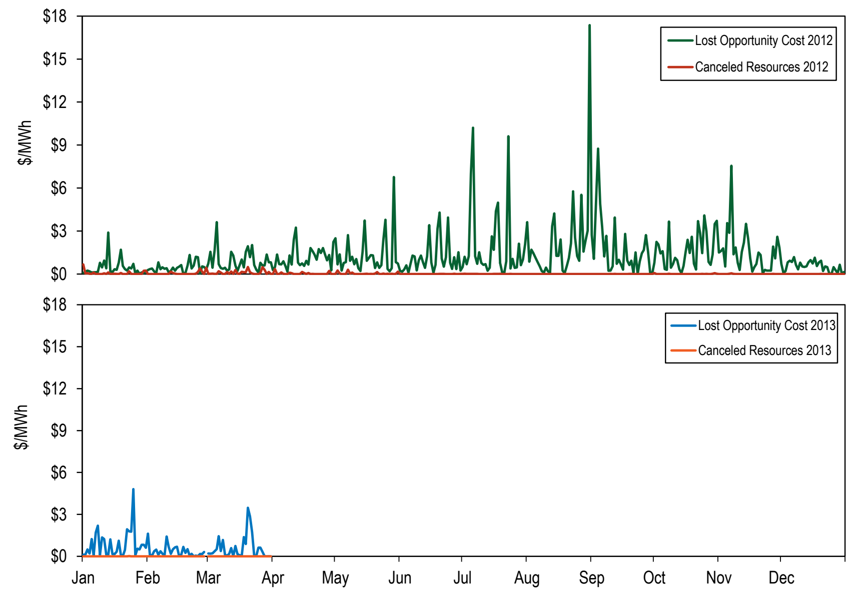


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and the first three months of 2013. The lost opportunity rate averaged $0.655 per MWh. The highest lost opportunity cost rate occurred on January 25, when it reached $4.805 per MWh.

Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013



17 See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Balancing Operating Reserve Cost Allocation" p.101 for a more detailed description of how the cost of balancing operating reserves are allocated

Table 3-11 shows the average rates for each region in each category for the first three months of 2012 and 2013.

Table 3-11 Operating reserve rates ($/MWh): January through March 2012 and 2013

Rate	Jan - Mar 2012 ($/MWh)	Jan - Mar 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.088	0.082	(0.005)	(6.2%)
Day-Ahead with Unallocated Congestion	0.088	0.114	0.026	29.6%
RTO Reliability	0.021	0.058	0.037	172.8%
East Reliability	0.001	0.065	0.064	6,408.4%
West Reliability	0.176	0.003	(0.172)	(98.2%)
RTO Deviation	0.782	1.001	0.220	28.1%
East Deviation	0.305	5.967	5.661	1,854.1%
West Deviation	0.062	0.055	(0.006)	(10.5%)
Lost Opportunity Cost	0.603	0.655	0.052	8.7%
Canceled Resources	0.070	0.000	(0.070)	(99.7%)

Table 3-12 shows the operating reserve cost of a 1 MW transaction during the first three months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $6.926 per MWh with a maximum rate of $32.879 per MWh, a minimum rate of $0.231 per MWh and a standard deviation of $8.324 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 3-12 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-12 Operating reserve rates statistics ($/MWh): January through March 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	32.847	6.815	0.024	8.344
	DEC	32.879	6.926	0.231	8.324
	DA Load	0.283	0.112	0.000	0.061
	RT Load	3.610	0.108	0.000	0.412
	Deviation	32.847	6.815	0.024	8.344
West	INC	12.913	1.524	0.024	2.156
	DEC	12.989	1.636	0.113	2.161
	DA Load	0.283	0.112	0.000	0.061
	RT Load	0.802	0.057	0.000	0.121
	Deviation	12.913	1.524	0.024	2.156

Operating Reserve Determinants

Table 3-13 shows the determinants used to allocate the regional balancing operating reserve charges for the first three months of 2012 and 2013. Total real-time load and real-time exports were 7,329,735 MWh or 3.8 percent higher in the first three months of 2013 compared to the first three months of 2012. Total deviations summed across the demand, supply, and generator categories were lower in the first three months of 2013 compared to the first three months of 2012 by 4,601,051 MWh or 13.3 percent.

Table 3-13 Balancing operating reserve determinants (MWh): January through March 2012 and 2013

		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
Jan - Mar 2012	RTO	188,414,264	6,264,235	194,678,500	19,277,166	7,653,318	7,692,007	34,622,491
	East	88,335,848	2,908,479	91,244,327	11,852,025	4,441,592	3,231,124	19,524,742
	West	100,078,417	3,355,756	103,434,173	7,341,579	3,193,440	4,460,883	14,995,902
Jan - Mar 2013	RTO	197,195,752	4,812,483	202,008,234	17,995,824	4,418,797	7,606,819	30,021,440
	East	93,547,149	3,081,730	96,628,879	9,724,224	2,248,085	3,137,498	15,109,806
	West	103,648,603	1,730,753	105,379,356	7,714,724	2,031,099	4,469,321	14,215,144
Difference	RTO	8,781,487	(1,451,753)	7,329,735	(1,281,342)	(3,234,521)	(85,189)	(4,601,051)
	East	5,211,301	173,250	5,384,552	(2,127,801)	(2,193,508)	(93,627)	(4,414,936)
	West	3,570,186	(1,625,003)	1,945,183	373,145	(1,162,341)	8,438	(780,758)

Table 3-14 Deviations by transaction type: January through March 2013

Deviation Category		Deviation (MWh)			Share		
	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	267,701	89,911	177,790	0.9%	0.6%	1.3%
	DECs Only	2,183,908	848,032	779,000	7.3%	5.6%	5.5%
	Exports Only	1,204,248	739,625	464,623	4.0%	4.9%	3.3%
	Load Only	11,407,941	6,851,590	4,556,351	38.0%	45.3%	32.1%
	Combination with DECs	1,547,221	836,033	711,187	5.2%	5.5%	5.0%
	Combination without DECs	1,384,806	359,033	1,025,773	4.6%	2.4%	7.2%
Supply	Bilateral Purchases Only	399,789	317,910	81,879	1.3%	2.1%	0.6%
	Imports Only	1,861,799	906,891	954,908	6.2%	6.0%	6.7%
	INCs Only	1,254,580	392,555	722,411	4.2%	2.6%	5.1%
	Combination with INCs	882,997	613,344	269,653	2.9%	4.1%	1.9%
	Combination without INCs	19,632	17,385	2,247	0.1%	0.1%	0.0%
Generators		7,606,819	3,137,498	4,469,321	25.3%	20.8%	31.4%
Total		30,021,440	15,109,806	14,215,144	100.0%	100.0%	100.0%

Deviations fall into three categories, demand, supply and generator deviations. Table 3-14 shows the different categories by the type of transactions that incur deviations. For example, 38.0 percent of all RTO deviations in the first three months of 2013 were from participants that only had load transactions. In the first three months of 2013, 19.5 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 80.5 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Operating Reserve Credits

Table 3-15 shows the totals for each credit category for the first three months of 2012 and 2013. During the first three months of 2013, 62.5 percent of total operating reserve credits were in the balancing category. This percentage decreased 4.2 percentage points from the 66.7 percent in the first three months of 2012.

Table 3-15 Credits by operating reserve category: January through March 2012 and 2013

Category	Type	Jan - Mar 2012	Jan - Mar 2013	Change	Percentage Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Day-Ahead	Generators	$18,022,535	$17,425,457	($597,077)	(3.3%)	14.7%	6.9%
	Imports	$220	$0	($220)	(100.0%)	0.0%	0.0%
	Load Response	$0	$0	$0	NA	0.0%	0.0%
Balancing	Canceled Resources	$2,415,961	$7,218	($2,408,743)	(99.7%)	2.0%	0.0%
	Generators	$56,298,453	$139,225,870	$82,927,417	147.3%	45.8%	54.8%
	Imports	$31,794	$33,538	$1,745	5.5%	0.0%	0.0%
	Load Response	$83,009	$853	($82,157)	(99.0%)	0.1%	0.0%
	Local Constraints Control	$2,277,006	$79,563	($2,197,443)	(96.5%)	1.9%	0.0%
	Lost Opportunity Cost	$20,871,023	$19,664,029	($1,206,994)	(5.8%)	17.0%	7.7%
Reactive Services	Day-Ahead	$0	$48,309,209	$48,309,209	NA	0.0%	19.0%
	Local Constraints Control	$0	$0	$0	NA	0.0%	0.0%
	Lost Opportunity Cost	$706,638	$105,781	($600,856)	(85.0%)	0.6%	0.0%
	Reactive Services	$21,985,676	$7,164,366	($14,821,311)	(67.4%)	17.9%	2.8%
	Synchronous Condensing	$82,034	$0	($82,034)	(100.0%)	0.1%	0.0%
Synchronous Condensing		$47,278	$1,873	($45,404)	(96.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$0	$21,663,650	$21,663,650	NA	0.0%	8.5%
	Balancing	$0	$528,536	$528,536	NA	0.0%	0.2%
	Testing	$0	$18,460	$18,460	NA	0.0%	0.0%
Total		$122,821,626	$254,228,403	$131,406,777	107.0%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-16 shows the distribution of total operating reserve credits by unit type for the first three months of 2012 and 2013. Credits paid to all unit types using fossil fuels increased in the first three months of 2013 compared to the first three months of 2012. Combined cycle units increased 329.6 percent or $85.7 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In the first three months of 2013, 43.9 percent of all operating reserve credits paid to units were paid to combined cycle units, 22.7 percentage points more than the share in the first three months of 2012.

Table 3-16 Operating reserve credits by unit type: January through March 2012 and 2013

Unit Type	Jan - Mar 2012	Jan - Mar 2013	Change	Percentage Change	Jan - Mar 2012 Share	Jan - Mar 2013 Share
Battery	$0	$0	$0	0.0%	0.0%	0.0%
Combined Cycle	$25,984,786	$111,641,562	$85,656,776	329.6%	21.2%	43.9%
Combustion Turbine	$31,768,029	$37,074,077	$5,306,048	16.7%	25.9%	14.6%
Diesel	$2,063,199	$3,635,263	$1,572,064	76.2%	1.7%	1.4%
Fuel Cell	$0	$0	$0	0.0%	0.0%	0.0%
Hydro	$219,411	$0	($219,411)	(100.0%)	0.2%	0.0%
Nuclear	$0	$0	$0	0.0%	0.0%	0.0%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$58,679,977	$90,796,221	$32,116,245	54.7%	47.8%	35.7%
Steam - Other	$1,633,408	$8,799,378	$7,165,970	438.7%	1.3%	3.5%
Wind	$2,357,793	$2,247,511	($110,282)	(4.7%)	1.9%	0.9%
Total	$122,706,603	$254,194,012	$131,487,409	107.2%	100.0%	100.0%

Table 3-17 Operating reserve credits by unit type: January through March 2013

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	52.6%	69.2%	100.0%	13.0%	5.0%	9.3%	0.0%	0.0%
Combustion Turbine	5.7%	12.9%	0.0%	0.0%	77.6%	5.0%	100.0%	0.1%
Diesel	0.0%	0.1%	0.0%	10.0%	0.1%	6.3%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	41.6%	11.5%	0.0%	77.0%	5.8%	79.4%	0.0%	99.9%
Steam - Others	0.1%	6.3%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	11.4%	0.0%	0.0%	0.0%
Total	$17,425,457	$139,225,870	$7,218	$79,563	$19,664,029	$55,579,356	$1,873	$22,210,646

Table 3-17 shows the distribution of operating reserve credits by unit type in the first three months of 2013. Combined cycle units received 52.6 percent of the day-ahead generator credits in the first three months of 2013, 10.0 percentage points higher than the share received in the first three months of 2012. Combined cycle units received 69.2 percent of the balancing generator credits in the first three months of 2013, 51.1 percentage points higher than the share received in the first three months of 2012. Combustion turbines and diesels received 77.7 percent of the lost opportunity cost credits, 16.8 percentage points lower than the share received in the first three months of 2012.

Table 3-17 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first three months of 2013, combined cycle and coal units received 88.7 percent of all reactive services credits, 2.8 percentage points higher than the share received in the first three months of 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.9 percent of all black start services credits.

Economic and Noneconomic Generation[18]

Economic dispatch generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 3-18 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

18 The analysis of economic and noneconomic generation is based on the units' incremental offer, the value used by PJM to calculate LMP. The analysis does not include no load or startup cost.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the additional hourly no load and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs. In the first three months of 2013, 31.6 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 30.8 percent of the real-time generation was eligible for balancing operating reserve credits.[19]

Table 3-18 Day-ahead and real-time generation (GWh): January through March 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	206,252	65,216	31.6%
Real-Time	202,674	62,430	30.8%

Table 3-19 shows PJM's economic and noneconomic generation eligible for operating reserve credits. In the first three months of 2013, 82.3 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.3 percent of the real-time generation eligible for operating reserve credits was economic.

Table 3-19 Day-ahead and real-time economic and noneconomic generation (GWh): January through March 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	53,691	11,525	82.3%	17.7%
Real-Time	42,009	20,421	67.3%	32.7%

19 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

Table 3-20 shows the generation receiving day-ahead and balancing operating reserve credits. In the first three months of 2013, 5.9 percent of the day-ahead generation eligible for operating reserve credits was made whole and 9.1 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-20 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through March 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	65,216	3,871	5.9%
Real-Time	62,430	5,699	9.1%

Geography of Charges and Credits

Table 3-21 shows the geography of charges and credits in the first three months of 2013. Table 3-21 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AEP Control Zone paid 6.0 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 2.8 percent of the corresponding credits. The AEP Control Zone received less operating reserve credits than operating reserve charges paid. Transactions in the PSEG Control Zone paid 7.9 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 57.9 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid. Table 3-21 also shows that 79.7 percent of all charges were allocated in control zones, 6.3 percent in hubs and 14.0 percent in interfaces.

Table 3-21 Geography of regional charges and credits: January through March 2013[20]

Location		Charges	Credits	Balance	Shares: Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$2,518,200	$1,080,695	($1,437,505)	1.4%	0.6%	1.5%	0.0%
	AEP	$10,642,707	$4,882,011	($5,760,695)	6.0%	2.8%	6.2%	0.0%
	AP - DLCO	$6,325,474	$4,700,303	($1,625,171)	3.6%	2.7%	1.7%	0.0%
	ATSI	$5,555,723	$6,611,868	$1,056,145	3.2%	3.7%	0.0%	1.1%
	BGE - Pepco	$19,118,385	$7,027,732	($12,090,653)	10.8%	4.0%	12.9%	0.0%
	ComEd - External	$8,215,752	$5,105,259	($3,110,492)	4.7%	2.9%	3.3%	0.0%
	DAY - DEOK	$3,755,013	$167,809	($3,587,203)	2.1%	0.1%	3.8%	0.0%
	Dominion	$19,181,720	$13,065,661	($6,116,058)	10.9%	7.4%	6.5%	0.0%
	DPL	$5,602,863	$4,482,317	($1,120,546)	3.2%	2.5%	1.2%	0.0%
	JCPL	$5,801,052	$6,888,101	$1,087,049	3.3%	3.9%	0.0%	1.2%
	Met-Ed	$4,895,235	$954,070	($3,941,165)	2.8%	0.5%	4.2%	0.0%
	PECO	$12,296,327	$1,817,146	($10,479,180)	7.0%	1.0%	11.2%	0.0%
	PENELEC	$9,292,515	$1,222,441	($8,070,074)	5.3%	0.7%	8.6%	0.0%
	PPL	$12,970,177	$16,197,326	$3,227,149	7.4%	9.2%	0.0%	3.4%
	PSEG	$13,876,650	$102,119,835	$88,243,184	7.9%	57.9%	0.0%	94.3%
	RECO	$474,493	$0	($474,493)	0.3%	0.0%	0.5%	0.0%
	All Zones	$140,522,284	$176,322,574	$35,800,290	79.7%	100.0%	61.8%	100.0%
Hubs	AEP - Dayton	$566,784	$0	($566,784)	0.3%	0.0%	0.6%	0.0%
	Dominion	$719,366	$0	($719,366)	0.4%	0.0%	0.8%	0.0%
	Eastern	$139,945	$0	($139,945)	0.1%	0.0%	0.1%	0.0%
	New Jersey	$517,351	$0	($517,351)	0.3%	0.0%	0.6%	0.0%
	Ohio	$12,846	$0	($12,846)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$391,898	$0	($391,898)	0.2%	0.0%	0.4%	0.0%
	Western	$8,734,352	$0	($8,734,352)	5.0%	0.0%	9.3%	0.0%
	All Hubs	$11,082,542	$0	($11,082,542)	6.3%	0.0%	11.8%	0.0%
Interfaces	IMO	$1,553,006	$0	($1,553,006)	0.9%	0.0%	1.7%	0.0%
	Linden	$988,006	$0	($988,006)	0.6%	0.0%	1.1%	0.0%
	MISO	$1,095,329	$0	($1,095,329)	0.6%	0.0%	1.2%	0.0%
	Neptune	$465,418	$0	($465,418)	0.3%	0.0%	0.5%	0.0%
	NIPSCO	$1	$0	($1)	0.0%	0.0%	0.0%	0.0%
	Northwest	$23,119	$0	($23,119)	0.0%	0.0%	0.0%	0.0%
	NYIS	$5,075,060	$0	($5,075,060)	2.9%	0.0%	5.4%	0.0%
	OVEC	$347,185	$0	($347,185)	0.2%	0.0%	0.4%	0.0%
	South Exp	$3,424,647	$0	($3,424,647)	1.9%	0.0%	3.7%	0.0%
	South Imp	$11,779,516	$0	($11,779,516)	6.7%	0.0%	12.6%	0.0%
	All Interfaces	$24,751,287	$33,538	($24,717,749)	14.0%	0.0%	26.4%	0.0%
	Total	$176,356,114	$176,356,114	$0	100.0%	100.0%	100.0%	100.0%

20 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-22 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

Table 3-22 and Table 3-23 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 3-22 shows that on average, 17.4 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 87.6 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-22 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through March 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,089,238	$7,208,786	$1,160,254	$10,458,278	$66,359,694
Feb	$545,372	$11,135,895	$368,041	$12,049,308	$61,850,876
Mar	$590,935	$578,031	$594,689	$1,763,656	$10,980,626
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
East Generators Total	$3,225,545	$18,922,713	$2,122,984	$24,271,242	$139,191,197
PJM Total	$30,061,634	$90,153,613	$19,671,247	$139,886,495	$158,930,655
Share	10.7%	21.0%	10.8%	17.4%	87.6%

Table 3-23 Monthly balancing operating reserve charges and credits to generators (Western Region): January through March 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,557,578	$136,570	$1,593,455	$4,287,603	$11,079,752
Feb	$855,762	$55,905	$438,367	$1,350,034	$3,533,880
Mar	$923,732	$59,453	$794,118	$1,777,303	$5,083,561
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
West Generators Total	$4,337,072	$251,927	$2,825,941	$7,414,940	$19,697,193
PJM Total	$30,061,634	$785,112	$19,671,247	$50,517,993	$158,930,655
Share	14.4%	32.1%	14.4%	14.7%	12.4%

Table 3-23 also shows that generators in the Western Region paid 14.7 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 12.4 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-24 shows that on average in the first three months of 2013, generator charges were 13.7 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 3.5 percentage points higher than the average in the first three months of 2012. Generators received 99.99 percent of all operating reserve credits, while the remaining 0.01 percent were credits paid to import transactions and load response resources.

Table 3-24 Percentage of unit credits and charges of total credits and charges: 2012 and 2013

	2012		2013	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	10.8%	99.9%	12.2%	100.0%
Feb	8.2%	100.0%	14.1%	100.0%
Mar	11.7%	99.8%	8.0%	99.9%
Apr	13.6%	100.0%		
May	14.0%	100.0%		
Jun	13.6%	99.9%		
Jul	15.6%	99.8%		
Aug	14.6%	100.0%		
Sep	9.4%	100.0%		
Oct	12.6%	99.9%		
Nov	12.7%	99.8%		
Dec	8.8%	100.0%		
Average	10.2%	99.9%	13.7%	100.0%

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 3-25 shows the geography of reactive services charges. In the first three months of 2013, 65.2 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 1.5 percent were paid by real-time load in multiple zones and 33.4 percent were paid by real-time load across the entire RTO. In the first three months of 2013, resources in two control zones accounted for 99.2 percent of all reactive services costs allocated across the entire RTO.

Table 3-25 Geography of reactive services charges: January through March, 2013[21]

Location	Charges	Share of Charges
Single Zone	$36,185,210	65.2%
Multiple Zones	$829,591	1.5%
Entire RTO	$18,526,176	33.4%
Total	$55,540,976	100.0%

In the first three months of 2013, the top three zones accounted for 77.4 percent of all the reactive services charges allocated to single zones. Also, only two sets of control zones (multiple zones) shared the costs of reactive services.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.9 percent of all the black start services costs in the first three months of 2013. These costs resulted from noneconomic operation of units providing black start service under the Automatic Load Rejection (ALR) option.[22]

Synchronous condensing charges are allocated by zone. Resources in one control zone accounted for all synchronous condensing costs in the first three months of 2013.[23]

21 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

22 PJM and the MMU cannot publish more detailed information about the location of the costs of black start because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

23 PJM and the MMU cannot publish more detailed information about the location of the costs of synchronous condensing because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

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.

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 in the top 10 units remains high and it increased in the first three months of 2013 compared to the first three months of 2012. Table 3-26 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 48.6 percent of total operating reserve credits in the first three months of 2013, compared to 36.8 percent in the first three months of 2012.

Table 3-26 Top 10 operating reserve credits units (By percent of total system): January through March 2012 and 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Mar 2012	36.8%	0.8%
Jan - Mar 2013	48.6%	0.6%

Table 3-27 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories paid to generators. The shares of the top 10 organizations in all categories separately were above 89.0 percent.

Table 3-27 Top 10 units and organizations operating reserve credits: January through March 2013

		Top 10 units		Top 10 organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$11,766,789	67.5%	$16,621,387	95.4%
Balancing	Canceled Resources	$7,218	100.0%	$7,218	100.0%
	Generators	$103,039,794	74.0%	$132,815,757	95.4%
	Local Constraints Control	$79,563	100.0%	$79,563	100.0%
	Lost Opportunity Cost	$9,170,111	46.6%	$17,532,974	89.2%
Reactive Services		$33,118,771	59.6%	$55,030,527	99.0%
Synchronous Condensing		$1,873	100.0%	$1,873	100.0%
Black Start Services		$20,345,736	91.6%	$22,210,646	100.0%
Total		$123,652,432	48.6%	$230,774,449	90.8%

Table 3-28 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2013, 93.5 percent of all credits paid to these units were allocated to deviations while the remaining 6.5 percent were paid for reliability reasons.

Table 3-28 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through March 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$4,091,549	$2,631,918	$0	$14,179,155	$82,096,496	$40,677	$103,039,794
Share	4.0%	2.6%	0.0%	13.8%	79.7%	0.0%	100.0%

In the first three months of 2013, concentration in all operating reserve credits categories was high.[24,25] Operating reserve credits HHI was calculated based on each organization's daily credits for each category. Table 3-29 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 5372, for balancing operating reserve generator credits was 5291 and for lost opportunity cost credits was 5418.

24 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
25 Table 3-30 excludes the local constraints control categories.

Table 3-29 Daily operating reserve credits HHI: January through March 2013

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	5372	1254	10000	100.0%	58.6%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
Balancing	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	5291	1511	9888	99.4%	64.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	95.2%
	Lost Opportunity Cost	5418	1182	10000	100.0%	50.1%
Reactive Services		4060	2366	9728	98.6%	33.2%
Synchronous Condesing		10000	10000	10000	100.0%	100.0%
Black Start Services		9973	9063	10000	100.0%	99.9%
Total		9973	9063	10000	85.4%	40.1%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirement (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[26] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed but a unit submitted as must run by a participant cannot set LMP and is not eligible for day-ahead operating reserve credits.[27] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 3-30 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first three months of 2013, 4.1 percent of the total day-ahead generation was scheduled as must run by PJM, 2.3 percentage points higher than the first three months of 2012.[28]

26 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.
27 See "PJM eMkt Users Guide" Section Managing Unit Data (version June, 2012) p. 40.
28 PJM increased the amount of generation scheduled as must run on September 13, 2012. See 2012 State of the Market Report for PJM: Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Table 3-30 Day-ahead generation scheduled as must run by PJM: 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%			
May	62,986	1,944	3.1%			
Jun	69,190	1,841	2.7%			
Jul	82,984	3,618	4.4%			
Aug	76,161	2,438	3.2%			
Sep	63,535	2,902	4.6%			
Oct	60,656	3,509	5.8%			
Nov	62,985	3,542	5.6%			
Dec	68,759	2,347	3.4%			
Total	195,307	3,611	1.8%	206,252	8,559	4.1%

Table 3-31 Day-ahead generation scheduled as must run by PJM by category: 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Total	1,287	3,536	947	2,789	8,559
Share	15.0%	41.3%	11.1%	32.6%	100.0%

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. Table 3-31 shows the total day-ahead generation scheduled as must run by PJM by category. In the first three months of 2013, 67.4 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 15.0 percent were credits paid to units scheduled to provide black start services, 41.3 percent were credits paid to units scheduled to provide reactive services and 11.1 percent were normal day-ahead operating reserve credits paid to units scheduled noneconomic. The remaining 32.6 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Total day-ahead operating reserve credits in the first three months of 2013 were $8.8 million, 50.8 percent of that total was paid to units scheduled as must run by PJM, not scheduled to provide black start or reactive services.

The MMU recommends PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. The overall 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.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in day-ahead but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit will have to pay.For purposes of this report, this lost opportunity cost will be referred as day-ahead lost opportunity cost.[29] 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 due to a transmission constraint or other reliability issue, the unit will receive a credit for lost opportunity cost based on the desired output. For purposes of this report, this lost opportunity cost will be referred as real-time lost opportunity cost.

In the first three months of 2013, lost opportunity cost credits decreased by $1.2 million or 5.8 percent compared to the first three months of 2012. The decrease of $1.2 million is comprised of a decrease of $4.0 million of day-ahead lost opportunity cost and an increase of $2.7 million of real-time lost opportunity cost. Table 3-34 shows the monthly composition of lost opportunity cost credits in 2012 and 2013.

Day-ahead lost opportunity cost (payments to combustion turbines and diesels scheduled in the Day-Ahead Market and not requested in real time) continue to receive the majority of all lost opportunity cost credits. In the first three months of 2013, day-ahead lost opportunity cost were 80.2 percent of all lost opportunity cost credits. Combustion turbines and diesels are only eligible for day-ahead lost opportunity cost if the units are scheduled in day ahead. Table 3-33 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In the first three months of 2013, PJM scheduled 2,125 GWh from combustion turbines and diesels, of which 58.4 percent was not requested by PJM in real time and of which 48.1 percent received lost opportunity cost credits, 19.2 percentage points lower than the first three months of 2012.

Table 3-32 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,116,947	$332,282	$5,449,229	$8,862,207	$1,840,110	$10,702,318
Feb	$4,277,162	$366,971	$4,644,133	$2,050,724	$1,245,178	$3,295,902
Mar	$10,327,361	$450,299	$10,777,660	$4,854,970	$810,838	$5,665,808
Apr	$11,814,780	$692,309	$12,507,090			
May	$15,806,150	$3,502,912	$19,309,062			
Jun	$14,502,682	$677,375	$15,180,057			
Jul	$27,875,651	$3,066,115	$30,941,767			
Aug	$25,573,420	$1,202,079	$26,775,499			
Sep	$19,723,184	$1,825,454	$21,548,638			
Oct	$12,391,362	$7,619,940	$20,011,303			
Nov	$14,547,688	$4,073,072	$18,620,760			
Dec	$5,177,551	$987,447	$6,164,998			
Total	$19,721,471	$1,149,552	$20,871,023	$15,767,902	$3,896,126	$19,664,028
Share of Total	94.5%	5.5%	100.0%	80.2%	19.8%	100.0%

29 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not called in real time incurs in balancing spot energy charges since it has to cover its day-ahead MWh position in real time.

Table 3-33 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	572	435	373	886	638	565
Feb	753	590	546	430	206	173
Mar	1,408	1,076	921	809	397	283
Apr	1,870	1,431	1,249			
May	1,926	1,250	1,046			
Jun	2,586	1,624	1,235			
Jul	3,898	1,424	988			
Aug	2,356	1,383	1,122			
Sep	1,635	1,169	1,032			
Oct	1,079	895	797			
Nov	1,319	1,018	823			
Dec	851	678	625			
Total	2,734	2,101	1,840	2,125	1,241	1,022
Share	100.0%	76.9%	67.3%	100.0%	58.4%	48.1%

Table 3-34 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total
Jan	$4,857,442	$355,007	$5,212,449	$8,166,901	$695,307	$8,862,207
Feb	$4,382,996	$154,019	$4,537,015	$1,860,546	$190,178	$2,050,724
Mar	$9,661,923	$894,042	$10,555,965	$3,031,710	$1,823,260	$4,854,970
Apr	$10,846,998	$1,028,201	$11,875,199			
May	$12,925,885	$2,775,886	$15,701,771			
Jun	$12,550,655	$2,163,079	$14,713,734			
Jul	$13,911,706	$13,967,989	$27,879,694			
Aug	$22,219,006	$3,415,961	$25,634,967			
Sep	$17,783,763	$2,196,639	$19,980,402			
Oct	$11,185,166	$1,296,974	$12,482,141			
Nov	$12,704,380	$2,130,370	$14,834,749			
Dec	$4,979,204	$364,570	$5,343,774			
Total	$18,902,361	$1,403,068	$20,305,429	$13,059,157	$2,708,745	$15,767,902
Share of Total	93.1%	6.9%	100.0%	82.8%	17.2%	100.0%

In the first three months of 2013, the top three control zones in which generation received lost opportunity cost credits, ATSI, AP and ComEd accounted for 70.3 percent of all lost opportunity cost credits, 54.0 percent of all the day-ahead generation from combustion turbines and diesels and 82.0 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and diesels receive lost opportunity cost credits on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 3-34 shows the lost opportunity costs credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 3-34 shows that in the first three months of 2013, $13.1 million or 82.8 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time.

PJM may not run units in real time if the real-time value of that energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 3-35 shows the total day-ahead generation from combustion turbines and diesels that were not called in real time by PJM and received lost opportunity cost credit. Table 3-35 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first three months of 2013, 75.7 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 24.3 percent was noneconomic.

Table 3-35 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[30]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445	548	121	669
Feb	422	248	670	171	53	224
Mar	805	287	1,092	272	145	417
Apr	1,126	329	1,455			
May	875	363	1,237			
Jun	835	667	1,501			
Jul	826	402	1,228			
Aug	946	397	1,343			
Sep	880	305	1,185			
Oct	710	193	903			
Nov	782	280	1,062			
Dec	434	298	732			
Total	1,536	671	2,208	991	319	1,310
Share	69.6%	30.4%	100.0%	75.7%	24.3%	100.0%

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[31] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU has not formally recommended these to the MIC for consideration although they were brought to the attention of the MIC.

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.
- **No load and startup costs:** Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not dispatched in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost. The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference

30 The total generation in Table 3-36 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-36 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

31 See "Meeting Minutes," from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (April 4, 2012)

between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the lost opportunity cost in the PJM Energy Markets for units scheduled in day ahead but which are backed down or not dispatched in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real time by PJM should be paid lost opportunity cost based on the area between the real time LMP and their offer curve between the actual and desired output points. Units scheduled in day ahead and not dispatched in real time should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between zero output and scheduled output points. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' price schedule if available and the unit does not fail the TPS test.

Table 3-36 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first three months of 2013, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by $6.7 million, or 34.0 percent, if all these changes had been implemented.[32]

32 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

Table 3-36 Impact on energy market lost opportunity cost credits of rule changes: January through March 2013

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$3,896,126	$15,767,902	$19,664,028
Impact 1: Committed Schedule	$191,053	$1,616,540	$1,807,593
Impact 2: Eliminating DA LMP	NA	($57,914)	($57,914)
Impact 3: Using Offer Curve	($546,911)	$894,669	$347,758
Impact 4: Including No Load Cost	NA	($7,202,071)	($7,202,071)
Impact 5: Including Startup Cost	NA	($1,581,000)	($1,581,000)
Net Impact	($355,858)	($6,329,776)	($6,685,634)
Credits After Changes	$3,540,269	$9,438,125	$12,978,394

Table 3-37 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy lost opportunity cost credits would have been reduced by $6.7 million, or 33.8 percent, if the two proposed modifications had been implemented.

Table 3-37 Impact on energy market lost opportunity cost credits of proposed rule changes: January through March 2013

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$3,896,126	$15,767,902	$19,664,028
Impact 1: Committed Schedule	$191,053	$1,616,540	$1,807,593
Impact 2: Including No Load Cost	NA	($6,957,137)	($6,957,137)
Impact 3: Including Startup Cost	NA	($1,500,685)	($1,500,685)
Net Impact	$191,053	($6,841,282)	($6,650,229)
Credits After Changes	$4,087,179	$8,926,619	$13,013,799

Black Start Service Units

Certain units located in the AEP control zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs should be allocated as black start charges. This recommendation was made effective on December 1, 2012.[33]

In the first three months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $22.2 million, 94.8 percent of these costs was paid by peak transmission use in the AEP control zone while the remaining 5.2 percent was paid by non-zone peak transmission use.

PJM and AEP have issued two requests for proposal (RFP) seeking additional black start capability for the AEP control zone, the results from the latest RFP are still pending. PJM has approved new rules concerning black start service procurement, and the new selection process will be effective on April 1, 2015.[34,35]

Con Edison – 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.[36] These units are often run out-of-merit and received substantial balancing operating reserve 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.

Reactive / Voltage Support Units

Certain units located in the BGE and Pepco control zones are committed to provide reactive support to the AP-South interface. The AP-South interface consists of four 500 kV transmission lines that connected the Western and Eastern regions of PJM. PJM approved in the 2012 Regional Transmission Expansion Planning (RTEP) seven reactive upgrades to solve identified N-1-1 low voltage NERC criteria violations, and five of the seven upgrades are located in substations at or near the AP-South interface. These upgrades should reduce the need for noneconomic operation of units to provide reactive support to the AP-South interface.

33 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
34 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at "Black Start Service".
35 See "Manual 14D: Generator Operational Requirement" Revision 23 (April 1, 2013) at "Section 10: Black Start Generation Procurement".
36 See the *2012 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.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[37] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

In the first three months of 2013, units providing reactive services were paid $1.5 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 49.2 percent were paid by deviations in the RTO Region, 34.3 percent by real-time load and real-time exports in the RTO Region and 16.5 percent by deviations in the Eastern and Western Regions.

Table 3-38 shows the impact of these credits in each of the balancing operating reserve categories.

37 OATT Attachment K - Appendix § 3.2.3B (f).

Table 3-38 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through March 2013

		Balancing Operating Reserve Rates ($/MWh)		Difference	
Category	Region	Current	Without Credits to Units Providing Reactive Services	($/MWh)	Percentage
Reliability	RTO	0.058	0.055	(0.002)	(4.3%)
	East	0.065	0.065	0.000	0.0%
	West	0.003	0.003	0.000	0.0%
Deviation	RTO	1.001	0.977	(0.024)	(2.4%)
	East	5.967	5.956	(0.011)	(0.2%)
	West	0.055	0.049	(0.006)	(10.4%)

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[38,39] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[40]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be equal to the positive difference between total offer (including no load and startup costs) and energy revenues. In addition, the MMU recommends that reactive services credits be calculated on segments which include all hours for which unit provides reactive service. Segments should be the higher of hours needed for reactive support and minimum run time.

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do, while accounting for the impact of such payments on the profitability of the transactions.

In the first three months of 2013, 52.8 percent of all up-to congestion transactions were profitable.[41]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied. It was assumed that up-to congestion transactions would have had the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, only 45.8 percent of all up-to congestion transactions would have been made. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

Table 3-39 shows the impact that including the identified 45.8 percent of up-to congestion transactions in the allocation of operating reserve charges would have had on the operating reserve charge rates in the first three months of 2013. For example, the RTO deviations rate would have been reduced by 74.7 percent.

Table 3-39 Up-to congestion transactions impact on operating reserve rates: January through March 2013

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.082	0.068	(0.014)	(17.4%)
RTO Deviations	1.001	0.253	(0.748)	(74.7%)
East Deviations	5.967	2.347	(3.619)	(60.7%)
West Deviations	0.055	0.010	(0.045)	(82.0%)
Lost Opportunity Cost	0.655	0.166	(0.489)	(74.7%)
Canceled Resources	0.000	0.000	(0.000)	(74.7%)

The MMU recommends, while the up-to congestion transaction product remains and in the absence of a plan to allocate operating reserve charges to all relevant transactions, that up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This

38 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," from the PJM's MIC October 10, 2012 meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>.

39 See "Minutes," from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

40 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}> (Accessed January 11, 2013).

41 An up-to congestion transaction profitability is based on its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Confidentiality of Operating Reserves Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[42]

Operating reserves are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. Operating reserve charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the units receiving operating reserve payments. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of operating reserves information does exactly the opposite. There is no market in operating reserves and the absence of relevant information creates a very effective barrier to entry. The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region. This information would include the publication of operating reserve information by zone, by owner and by unit.

42 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement" Revision 9 (July 22, 2012), Market Data Posting .

Capacity Market

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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first three months of calendar year 2013, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

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	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.[2]
- 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 have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, 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 the 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.[4]

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

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

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

4 The terms *PJM* Region, *RTO Region* and *RTO* are synonymous in the *2012 State of the Market* Report for PJM, Section 4, "Capacity Market" and include all capacity within the PJM footprint.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future.[5] Effective with the 2012/2013 Delivery Year, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[6] Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] 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 period January 1, through March 31, 2013, PJM installed capacity decreased 115.1 MW or 0.1 percent from 182,011.1 MW on January 1 to 181,896.0 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2013, 41.8 percent was coal; 28.6 percent was gas; 18.2 percent was nuclear; 6.2 percent was oil; 4.3 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.

- **Market Concentration.** In the 2013/2014 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. 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.[9,10,11]

- **Imports and Exports.** Of the 44.7 MW of imports in the 2013/2014 RPM Third Incremental Auction, all 44.7 MW cleared. Of the cleared imports, 14.5 MW (32.4 percent) were from MISO.

- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,583.4 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (1,100.4 MW).

Market Conduct

- **2013/2014 RPM Third Incremental Auction.** Of the 410 generation resources which submitted offers, unit-specific offer caps were calculated for zero generation resources (0.0 percent). The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values.

5 See 126 FERC ¶ 61,275 (2009) at P 86.
6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 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.

9 See OATT Attachment DD § 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).

Market Performance

- The 2013/2014 RPM Third Incremental Auction was conducted in the first quarter of 2013. In the 2013/2014 RPM Third Incremental Auction, the RTO clearing price was $4.05 per MW-day.
- 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. The annual weighted average capacity price then declined to $86.33 per MW-day in 2012 before increasing again to $148.33 per MW-day in 2015.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd for January through March is 8.3 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[12]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through March is 85.6 percent, an increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **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 the first three months of 2013, 25.4 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

12 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 or the three months ending March 31, as downloaded from the PJM GADS database on May 2, 2013. 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.

Conclusion

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first three months of 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first three months of 2013.[13]

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[14,15,16,17] In 2011, 2012, and and 2013, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

13 For more complete conclusions, see *2012 State of the Market Report for PJM*, Section 4, "Capacity Market."
14 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).
15 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)
16 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).
17 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 4-2 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
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf
March 29, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130329.pdf

Installed Capacity

On January 1, 2013, PJM installed capacity was 182,011.1 MW (Table 4-3).[18] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 181,896.0 MW on March 31, 2013, a decrease of 115.1 MW or 0.1 percent over the January 1 level.[19,20] The 115.1 MW decrease was the result of new generation (26.0 MW), an increase in imports (35.0 MW), and capacity modifications (75.2 MW), offset by deactivations (166.0 MW), derates (76.4 MW), and additional exports (8.9 MW).

Table 4-3 PJM installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2013

	1-Jan-13		31-Jan-13		28-Feb-13		31-Mar-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	75,989.2	41.8%	76,020.6	41.8%	76,055.6	41.8%
Gas	52,024.2	28.6%	52,031.6	28.6%	51,987.9	28.6%	51,996.7	28.6%
Hydroelectric	7,879.8	4.3%	7,879.8	4.3%	7,879.8	4.3%	7,879.8	4.3%
Nuclear	33,024.0	18.1%	33,024.0	18.2%	33,014.7	18.2%	33,014.7	18.2%
Oil	11,531.2	6.3%	11,365.2	6.2%	11,361.2	6.2%	11,361.2	6.2%
Solar	47.0	0.0%	47.0	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	736.1	0.4%	736.1	0.4%	735.4	0.4%	735.4	0.4%
Wind	779.6	0.4%	779.6	0.4%	805.6	0.4%	805.6	0.4%
Total	182,011.1	100.0%	181,852.5	100.0%	181,852.2	100.0%	181,896.0	100.0%

RPM Capacity Market

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

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[21] In the first three months of 2013, a Third Incremental Auction was held in February for the 2013/2014 Delivery Year.

Market Structure

Supply

Offered MW in the 2013/2014 RPM Third Incremental Auction totaled 5,526.4 MW. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. PJM sell offers for the RTO in the 2013/2014 RPM Third Incremental Auction were 1,099.2 MW.

Demand

Participant buy bids in the 2013/2014 RPM Third Incremental Auction totaled 6,371.7 MW. Participant buy bids are submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity. PJM buy bids for the RTO in the 2013/2014 RPM Third Incremental Auction were 140.6 MW.

Market Concentration

Auction Market Structure

As shown in Table 4-4, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2013/2014 RPM Third Incremental Auction.[22] 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

18 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.

19 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.

20 Wind resources accounted for 805.6 MW of installed capacity in PJM on March 31, 2013. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

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

22 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.

the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[23,24,25]

Table 4-4 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.

Table 4-4 RSI results: 2012/2013 through 2015/2016 RPM Auctions[26]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 BRA				
RTO	0.84	0.63	98	98
MAAC/SWMAAC	0.77	0.54	15	15
EMAAC/PSEG	0.00	7.03	6	0
PSEG North	0.00	0.00	2	2
DPL South	0.00	0.00	3	3
2012/2013 ATSI FRR Integration Auction				
RTO	0.34	0.10	16	16
2012/2013 First Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.40	0.60	25	25
EMAAC	0.40	0.00	2	2
2012/2013 Second Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.62	0.64	33	33
EMAAC	0.00	0.00	2	2
2012/2013 Third Incremental Auction				
RTO/MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South	0.39	0.28	53	53
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2013/2014 Third Incremental Auction				
RTO	0.60	0.38	60	60
MAAC/SWMAAC/Pepco	0.01	0.02	4	4
EMAAC/PSEG/PSEG North/DPL South	0.38	0.22	7	7
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3

23 See OATT Attachment DD § 6.5.
24 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.
25 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).
26 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[27] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[28] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 4-1, Figure 4-2, and Figure 4-3.

Figure 4-1 PJM Locational Deliverability Areas

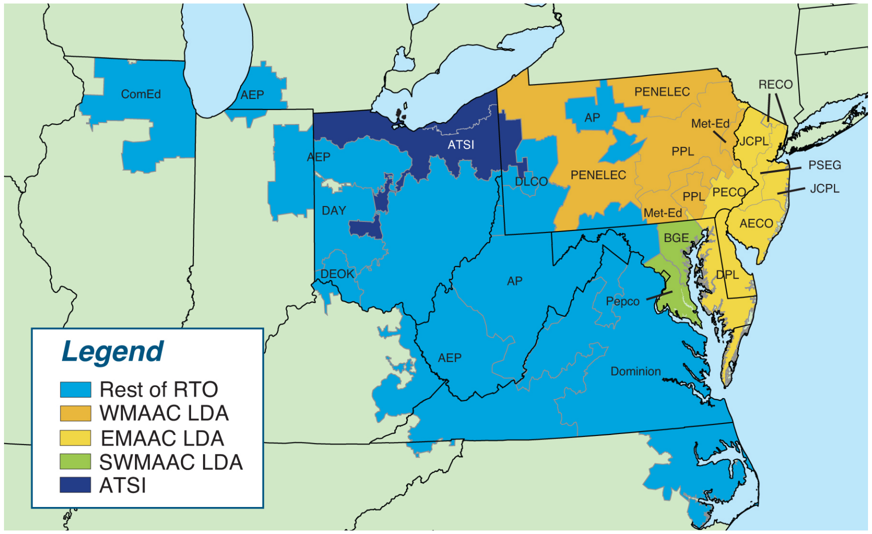


Figure 4-2 PJM RPM EMAAC subzonal LDAs

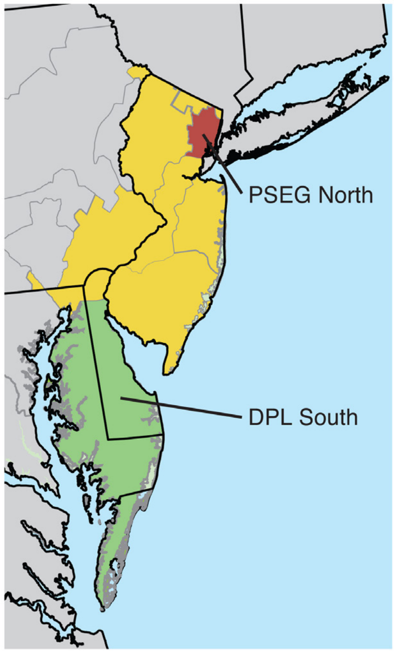
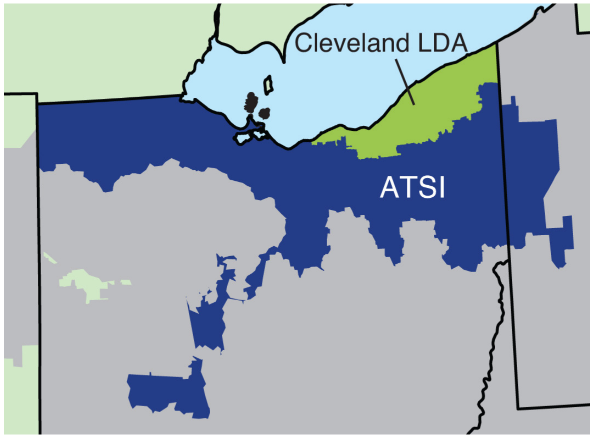


Figure 4-3 PJM RPM ATSI subzonal LDA



27 Prior to the 2012/2013 delivery year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
28 OATT Attachment DD § 5.10 (a) (ii).

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[29] There were a total of 44.7 MW of imports cleared in the 2013/2014 RPM Third Incremental Auction. Of these cleared imports, 14.5 MW (32.4 percent) were from MISO.

Demand-Side Resources

As shown in Table 4-5 and Table 4-7, capacity in the RPM load management programs was 10,583.4 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (1,100.4 MW). Table 4-6 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

29 OATT Attachment DD § 5.6.6(b).

Table 4-5 RPM load management statistics by LDA: June 1, 2011 to June 1, 2015[30,31]

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
DR cleared	1,826.6								
EE cleared	76.4								
DR net replacements	(1,052.4)								
EE net replacements	0.2								
ILR	9,032.6								
RPM load management @ 01-Jun-11	9,883.4								
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9		
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8		
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1		
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)		
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8		
DR cleared	10,779.6	6,466.6	2,735.7	1,788.8	155.4	1,185.0	534.8	661.9	
EE cleared	904.2	289.9	65.2	149.5	10.7	26.2	9.4	72.7	
DR net replacements	(1,098.9)	(1,016.1)	(626.2)	(196.3)	(13.1)	(510.3)	(224.5)	(96.4)	
EE net replacements	(1.5)	(1.1)	0.0	(1.1)	0.0	0.0	0.0	(1.1)	
RPM load management @ 01-Jun-13	10,583.4	5,739.3	2,174.7	1,740.9	153.0	700.9	319.7	637.1	
DR cleared	14,226.8	7,320.0	2,923.5	2,250.3	220.9	989.5	468.0	908.5	
EE cleared	956.4	276.9	35.2	169.8	8.1	14.9	7.6	51.4	
DR net replacements	(5.9)	(5.4)	(2.4)	(0.3)	0.0	(0.6)	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	15,177.3	7,591.5	2,956.3	2,419.8	229.0	1,003.8	475.6	959.9	
DR cleared	14,832.8	6,648.7	2,610.4	2,009.1	86.3	796.1	263.3	867.4	1,763.7
EE cleared	922.5	222.6	42.2	159.4	0.0	10.7	3.1	55.8	44.9
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-15	15,755.3	6,871.3	2,652.6	2,168.5	86.3	806.8	266.4	923.2	1,808.6

30 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.

31 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 4-6 RPM load management cleared capacity and ILR: 2007/2008 through 2015/2016[32,33,34]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	13,717.4	14,226.8	923.9	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0

Table 4-7 RPM load management statistics: June 1, 2007 to June 1, 2015[35,36]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(1,054.5)	(1,098.9)	(1.4)	(1.5)	10,160.7	10,583.4
01-Jun-14	14,641.3	15,183.2	(5.7)	(5.9)	0.0	0.0	14,635.6	15,177.3
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3

32 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.

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

34 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.

35 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.

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

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[37,38,39]

37 See OATT Attachment DD § 6.5.

38 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.

39 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 4-8 ACR statistics: 2013/2014 RPM Auctions

	2013/2014 Base Residual Auction		2013/2014 First Incremental Auction		2013/2014 Second Incremental Auction		2013/2014 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	580	49.6%	70	36.5%	55	33.7%	44	10.7%
ACR data input (APIR)	92	7.9%	27	14.1%	8	4.9%	0	0.0%
ACR data input (non-APIR)	15	1.3%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	6	0.5%	0	0.0%	4	2.5%	0	0.0%
Default ACR and opportunity cost	7	0.6%	4	2.1%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	201	49.0%
Uncapped planned uprate and default ACR	NA	NA	3	1.6%	10	6.1%	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	1	0.5%	5	3.1%	7	1.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	0	0.0%
Uncapped planned generation resources	20	1.7%	1	0.5%	11	6.7%	2	0.5%
Price takers	450	38.5%	86	44.8%	70	42.9%	156	38.0%
Total Generation Capacity Resources offered	1,170	100.0%	192	100.0%	163	100.0%	410	100.0%

2013/2014 RPM Third Incremental Auction

As shown in Table 4-8, 410 generation resources submitted offers in the 2013/2014 RPM Third Incremental Auction. The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values. Of the 410 generation resources, 201 generation resources elected offer cap option of 1.1 times the BRA clearing price (49.0 percent), two Planned Generation Capacity Resources had uncapped offers (0.5 percent), and seven generation resources had uncapped planned uprates along with price taker status for the existing portion (1.7 percent), while the remaining 156 generation resources were price takers (38.0 percent). Market power mitigation was applied to the sell offers for 17 generation resources.

Market Performance[40]

In the 2013/2014 RPM Third Incremental Auction, participant sell offers were 5,526.4 MW, while participant buy bids were 6,371.7 MW. Cleared participant sell offers in the RTO were 2,703.4 MW, while cleared participant buy bids were 3,168.4 MW. Released capacity by PJM was 605.6 MW, while procured capacity by PJM was 140.6 MW. As shown in Table 4-9, the RTO clearing price in the 2013/2014 RPM Third Incremental Auction was $4.05 per MW-day.

Figure 4-4 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

Table 4-10 shows RPM revenue by resource type for all RPM Auctions held to date with $1.5 billion for new/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 4-11 shows RPM revenue by calendar year for all RPM Auctions held to date.

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

Table 4-9 Capacity prices: 2007/2008 through 2015/2016 RPM Auctions

		RPM Clearing Price ($ per MW-day)								
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco	ATSI
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	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
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	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$10.00	$7.01
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$188.44	$30.00	$188.44	$188.44	$30.00	$4.05
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00

Table 4-10 RPM revenue by type: 2007/2008 through 2015/2016[41,42]

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,897	$558,715,114	$670,147,703	$880,020,384	$2,595,950,883
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$21,598,174	$40,247,604	$52,113,238	$125,507,380
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,804,645	$178,473,828	$186,311,568	$840,981,683
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,016,194,603	$1,745,438,458	$1,853,342,698	$2,656,149,396	$16,813,336,603
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,568,127	$12,950,135	$56,917,305	$62,882,021	$173,670,486
Gas existing	$1,460,544,471	$1,911,518,321	$2,276,961,764	$2,586,971,699	$1,607,317,731	$1,079,413,451	$1,846,432,716	$1,969,632,253	$2,473,484,871	$17,212,277,277
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$167,844,235	$184,293,676	$527,114,537	$1,155,793,124
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,853,673	$328,974,881	$384,329,997	$2,784,319,365
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$25,708	$6,591,114	$14,880,302	$21,508,521
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,550	$1,346,223,419	$1,460,152,259	$1,846,030,461	$12,130,180,851
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$502,172,373	$572,259,505	$715,618,319	$668,505,533	$368,084,004	$423,957,756	$689,864,789	$469,738,966	$562,402,530	$4,972,603,775
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,670,399	$3,896,120	$5,166,777	$33,327,814
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,943,130	$34,529,651	$35,405,293	$312,130,550
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$316,420	$1,977,705	$1,190,758	$3,324,459	$8,008,274
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$3,523,555	$3,152,447	$3,403,067	$11,392,384
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,373,205	$1,493,377	$1,768,330	$11,961,271
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$13,538,988	$31,173,865	$39,549,396	$124,220,216
Total	**$4,252,287,381**	**$6,087,147,586**	**$7,503,218,157**	**$8,449,652,496**	**$5,335,087,023**	**$3,871,714,635**	**$6,799,778,047**	**$7,293,948,503**	**$9,734,336,627**	**$59,327,170,456**

Table 4-11 RPM revenue by calendar year: 2007 through 2016[43]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$124.13	156,470.1	365	$7,089,510,863
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$161.62	164,563.9	152	$4,042,675,320

41 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.
42 The results for the ATSI Integration Auctions are not included in this table.
43 The results for the ATSI Integration Auctions are not included in this table.

Figure 4-4 History of capacity prices: Calendar year 1999 through 2015[44]

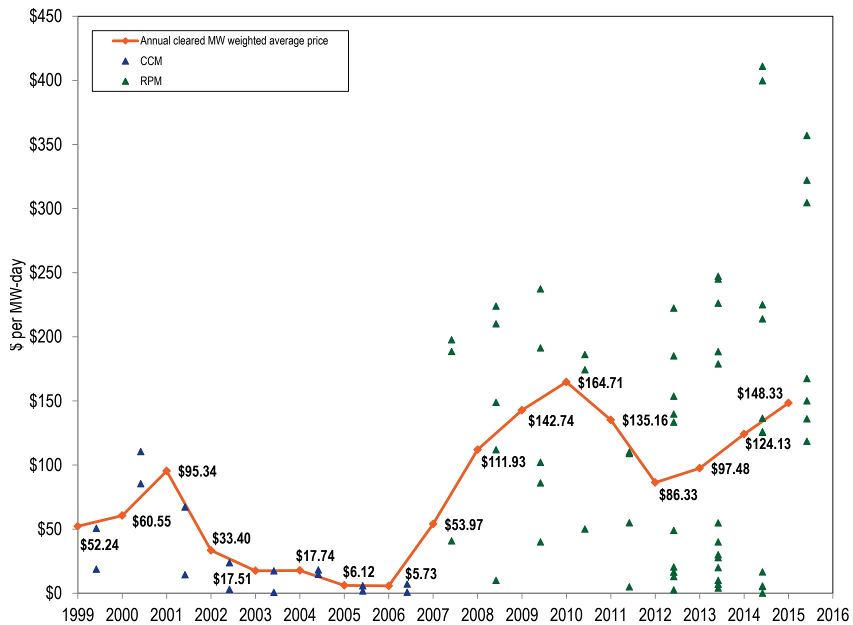


Table 4-12 shows the RPM annual charges to load. For the 2012/2013 planning year, RPM annual charges to load total approximately $3.9 billion.

44 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 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.

Table 4-12 RPM cost to load: 2012/2013 through 2015/2016 RPM Auctions[45,46,47]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2012/2013			
Rest of RTO	$16.74	65,495.4	$400,296,161
Rest of MAAC	$133.42	30,107.9	$1,466,181,230
Rest of EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
Total		131,727.1	$3,861,657,038
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
2014/2015			
Rest of RTO	$128.17	82,577.4	$3,863,199,144
Rest of MAAC	$137.60	30,833.8	$1,548,586,169
Rest of EMAAC	$137.61	20,460.8	$1,027,667,647
DPL	$145.32	4,625.7	$245,357,435
PSEG	$170.24	11,833.5	$735,288,837
Total		150,331.2	$7,420,099,231
2015/2016			
Rest of RTO	$134.62	84,948.0	$4,185,534,909
MAAC	$165.78	68,742.2	$4,170,968,816
ATSI	$294.03	14,940.4	$1,607,805,047
Total		168,630.6	$9,964,308,771

45 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
46 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.
47 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 2013/2014, 2014/2015, and 2015/2016 Net Load Prices are not finalized. The 2013/2014, 2014/2015, and 2015/2016 Obligation MW are not finalized.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance 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).[48]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In the first three months of 2013, nuclear units had a capacity factor of 99.0 percent. Combined cycle units ran less often, decreasing from a 63.0 percent capacity factor in the first three months of 2012 to a 52.3 percent capacity factor in the first three months of 2013. In contrast, the capacity factor for steam units increased from 39.8 percent in the first three months of 2012 to 51.4 percent in the first three months of 2013.

Table 4-13 PJM capacity factor (By unit type (GWh)): January through March 2012 and 2013[49]

	Jan-Mar 2012		Jan-Mar 2013	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	0.1%	0.1	0.2%
Combined Cycle	35,691.6	63.0%	29,133.2	52.3%
Combustion Turbine	557.1	0.8%	882.8	1.4%
Diesel	214.5	19.1%	138.2	15.4%
Diesel (Landfill gas)	277.7	52.6%	320.6	40.6%
Fuel Cell	0.0	0.0%	15.6	24.0%
Nuclear	70,637.4	96.3%	72,028.7	99.0%
Pumped Storage Hydro	1,227.8	10.2%	1,421.7	12.0%
Run of River Hydro	2,130.1	40.4%	2,155.0	41.3%
Solar	43.9	13.8%	59.8	11.1%
Steam	79,543.8	39.8%	91,730.3	51.4%
Wind	4,261.3	37.3%	4,788.1	34.8%
Total	194,585.3	45.6%	202,674.2	50.0%

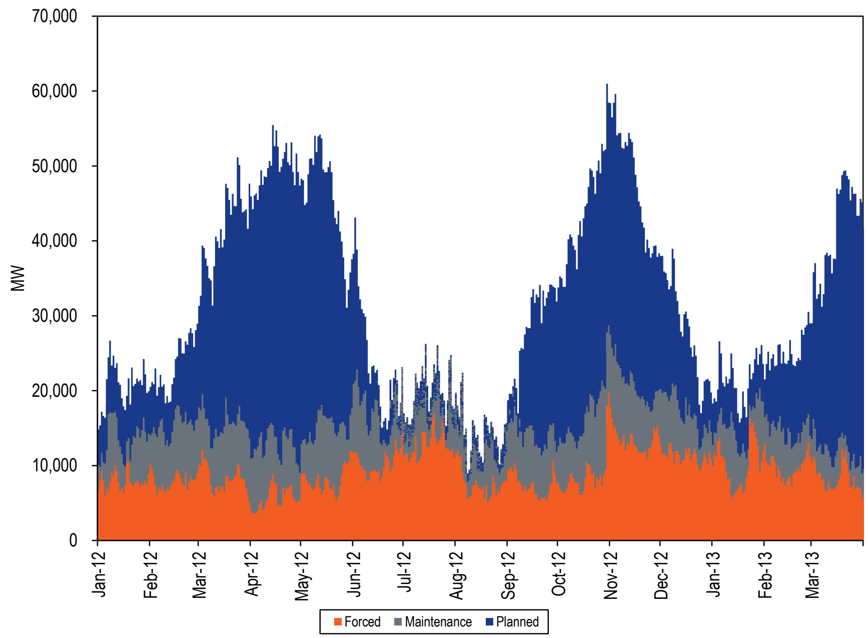
Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outage varies throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 4-5. The effect of seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

48 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.

49 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.

Figure 4-5 PJM outages (MW): January 2012 to March 2013



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

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 4-6. Metrics by unit type are shown in Table 4-14 through Table 4-17.

Figure 4-6 PJM equivalent outage and availability factors: 2007 to 2013

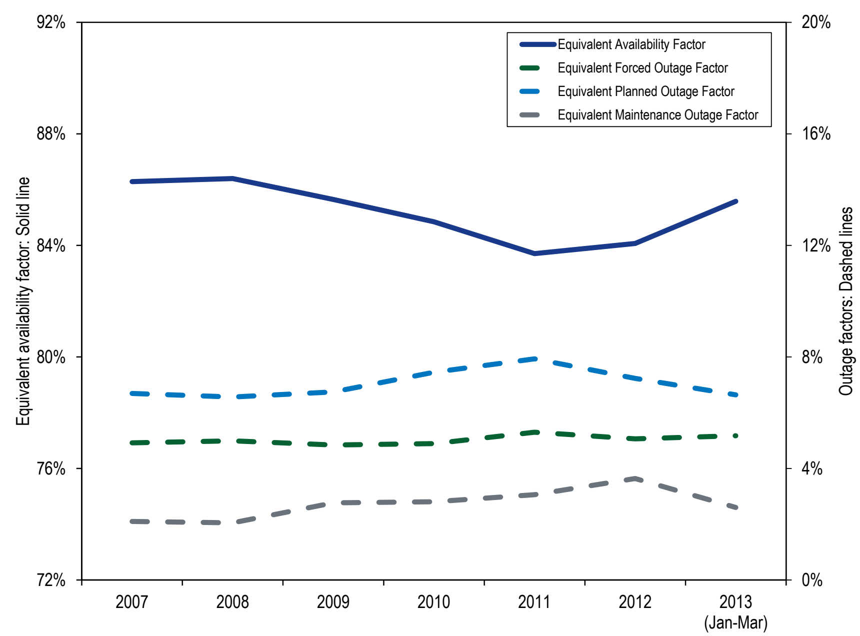


Table 4-14 EAF by unit type: 2007 through March, 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Mar)
Combined Cycle	89.7%	90.1%	87.8%	85.9%	85.4%	85.4%	84.1%
Combustion Turbine	90.5%	91.1%	93.2%	93.1%	91.8%	92.4%	90.8%
Diesel	86.4%	87.8%	91.2%	94.1%	94.8%	92.5%	95.4%
Hydroelectric	90.1%	88.8%	86.9%	88.8%	84.6%	88.8%	93.7%
Nuclear	93.1%	92.3%	90.1%	91.8%	90.1%	91.1%	95.6%
Steam	81.3%	81.6%	80.9%	79.0%	78.2%	77.8%	79.4%
Total	86.3%	86.4%	85.6%	84.8%	83.7%	84.1%	85.6%

Table 4-15 EMOF by unit type: 2007 through March, 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Mar)
Combined Cycle	2.0%	1.6%	3.0%	3.1%	2.4%	2.9%	2.8%
Combustion Turbine	2.5%	2.2%	2.3%	2.0%	2.4%	1.7%	0.9%
Diesel	1.8%	1.2%	1.2%	1.5%	2.0%	2.6%	1.3%
Hydroelectric	1.4%	2.1%	2.3%	1.9%	1.9%	2.1%	2.3%
Nuclear	0.3%	0.8%	0.6%	0.5%	1.2%	1.1%	0.3%
Steam	2.7%	2.6%	3.7%	3.9%	4.2%	5.6%	4.1%
Total	2.1%	2.1%	2.8%	2.8%	3.1%	3.6%	2.6%

Table 4-16 EPOF by unit type: 2007 through March, 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Mar)
Combined Cycle	5.9%	6.0%	6.3%	8.2%	9.7%	8.2%	8.4%
Combustion Turbine	2.5%	4.0%	2.8%	3.0%	3.8%	3.2%	2.8%
Diesel	0.7%	1.1%	0.6%	0.5%	0.1%	0.7%	0.1%
Hydroelectric	7.2%	7.8%	8.6%	8.6%	11.8%	6.3%	3.5%
Nuclear	5.3%	5.1%	5.2%	5.4%	6.1%	6.4%	3.7%
Steam	8.6%	8.0%	8.6%	9.4%	9.2%	8.8%	9.0%
Total	6.7%	6.6%	6.7%	7.5%	7.9%	7.2%	6.6%

Table 4-17 EFOF by unit type: 2007 through March, 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Mar)
Combined Cycle	2.3%	2.3%	2.9%	2.7%	2.6%	3.6%	4.8%
Combustion Turbine	4.5%	2.7%	1.6%	1.9%	2.0%	2.7%	5.5%
Diesel	11.2%	9.9%	7.0%	3.8%	3.2%	4.2%	3.2%
Hydroelectric	1.3%	1.3%	2.3%	0.7%	1.7%	2.8%	0.5%
Nuclear	1.3%	1.8%	4.1%	2.3%	2.6%	1.5%	0.5%
Steam	7.3%	7.9%	6.8%	7.7%	8.3%	7.8%	7.5%
Total	4.9%	5.0%	4.8%	4.9%	5.3%	5.1%	5.2%

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,[50] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

50 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.

Figure 4-7 shows the average EFORd since 2007 for all units in PJM.

Figure 4-7 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013

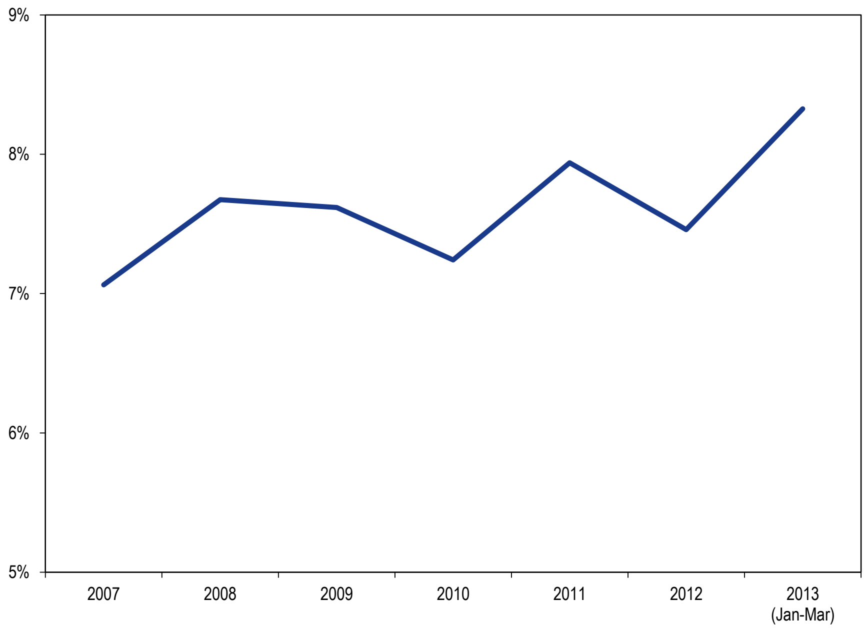


Table 4-18 shows the class average EFORd by unit type.

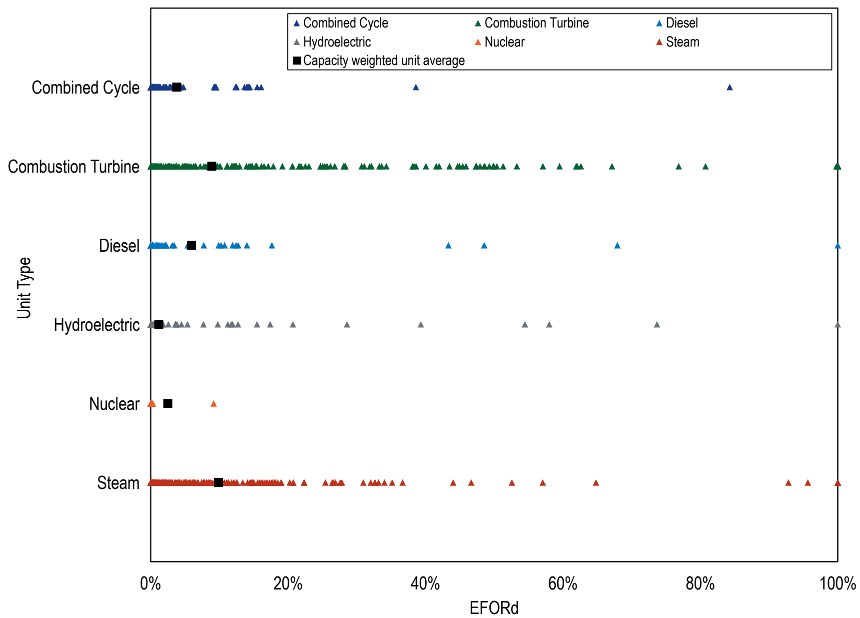
Table 4-18 PJM EFORd data for different unit types: 2007 through March, 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Mar)
Combined Cycle	3.7%	3.8%	4.3%	3.8%	3.5%	4.3%	5.4%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.1%	18.3%
Diesel	12.9%	11.2%	9.9%	5.9%	9.6%	5.5%	3.4%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	0.6%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	0.5%
Steam	9.2%	10.1%	9.4%	9.8%	11.3%	10.6%	9.5%
Total	7.1%	7.7%	7.6%	7.2%	7.9%	7.5%	8.3%

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 4-8. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance of EFORd, while nuclear units had the lowest variance in EFORd values.

Figure 4-8 PJM distribution of EFORd data by unit type: January through March, 2013



Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

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

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 of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

The PJM Capacity Market creates an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[51] An outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[52] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

However, nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market. That choice was made by PJM and can be modified without violating any NERC requirements.[53] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-19 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 25.4 percent of all forced outages. The second-largest contributor to OMC outages, lack of fuel, was the cause in of 31.5 percent of OMC outages and 8.0 percent of all forced outages. The NERC GADS guidelines in Appendix

51 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>.

52 For a list of these cause codes, see the Technical Reference for PJM Markets, at "Generator Performance: NERC OMC Outage Cause Codes" <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

53 It is unclear whether there were member votes taken on this issue.

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."

Table 4-19 OMC Outages: January through March, 2013

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	45.8%	11.6%
Lack of fuel	31.5%	8.0%
Flood	17.5%	4.5%
Other miscellaneous external problems	2.9%	0.7%
Other switchyard equipment external	0.9%	0.2%
Transmission system problems	0.7%	0.2%
Transmission line	0.3%	0.1%
Transmission equipment at the 1st substation	0.3%	0.1%
Lightning	0.1%	0.0%
Lack of water	0.1%	0.0%
Wet coal	0.0%	0.0%
Switchyard circuit breakers external	0.0%	0.0%
Transmission equipment beyond the 1st substation	0.0%	0.0%
Other fuel quality problems	0.0%	0.0%
Storms	0.0%	0.0%
Total	100.0%	25.4%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because the lack of fuel reasons are arguably not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[54]

If there were units in a constrained Locational Deliverability Area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules.[55]

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

55 See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf> When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

It is clear that OMC outages defined as lack of fuel should not be identified as OMC and should not be excluded from the calculation of XEFORd and EFORp.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, that PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

Table 4-20 shows the impact of OMC outages on EFORd. The difference is especially noticeable for steam units and combustion turbine units.

Table 4-20 PJM EFORd vs. XEFORd: January through March, 2013

	EFORd	XEFORd	Difference
Combined Cycle	5.4%	4.5%	0.9%
Combustion Turbine	18.3%	12.6%	5.7%
Diesel	3.4%	3.0%	0.5%
Hydroelectric	0.6%	0.6%	0.1%
Nuclear	0.5%	0.5%	0.0%
Steam	9.5%	7.4%	2.1%
Total	8.3%	6.3%	2.0%

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

PJM EFOF was 5.2 percent in 2013. This means there was 5.2 percent lost availability because of forced outages. Table 4-21 shows that forced outages for boiler tube leaks, at 15.7 percent of the systemwide EFOF, were the second-largest single contributor to EFOF.

Table 4-21 Contribution to EFOF by unit type by cause: January through March, 2013

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Catastrophe	10.2%	59.9%	11.0%	13.6%	0.0%	7.5%	16.1%
Boiler Tube Leaks	1.5%	0.0%	0.0%	0.0%	0.0%	22.3%	15.7%
Economic	1.5%	11.8%	0.1%	3.7%	0.0%	10.5%	9.4%
High Pressure Turbine	56.2%	0.0%	0.0%	0.0%	0.0%	1.4%	8.0%
Boiler Piping System	1.8%	0.0%	0.0%	0.0%	0.0%	8.6%	6.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	4.9%
Boiler Fuel Supply from Bunkers to Boiler	0.1%	0.0%	0.0%	0.0%	0.0%	5.3%	3.7%
Controls	2.0%	12.7%	0.0%	0.1%	0.0%	1.7%	3.5%
Feedwater System	0.2%	0.0%	0.0%	0.0%	13.4%	3.2%	2.5%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%	2.3%
Miscellaneous Boiler Tube Problems	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	1.9%
Fuel Quality	0.0%	0.0%	6.3%	0.0%	0.0%	2.2%	1.5%
Valves	0.0%	0.0%	0.0%	0.0%	0.5%	2.0%	1.4%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.3%
Stack Emission	0.4%	1.5%	0.0%	0.0%	0.0%	1.5%	1.3%
Electrical	0.4%	0.9%	8.1%	4.3%	0.3%	1.5%	1.3%
Auxiliary Systems	1.4%	1.8%	0.0%	0.0%	0.0%	1.1%	1.3%
Reserve Shutdown	0.0%	1.7%	37.7%	3.6%	0.0%	1.2%	1.2%
Personnel or Procedure Errors	0.5%	0.0%	0.0%	0.1%	0.0%	1.5%	1.1%
All Other Causes	23.7%	9.7%	36.7%	74.7%	85.8%	13.3%	15.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

56 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.

Table 4-22 shows the categories which are included in the economic category.[57] Lack of fuel that is considered Outside Management Control accounted for 85.4 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 14.4 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."[58] 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 4-22 Contributions to Economic Outages: January through March, 2013

	Contribution to Economic Reasons
Lack of fuel (OMC)	85.4%
Lack of fuel (Non-OMC)	14.4%
Lack of water (Hydro)	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.1%
Other economic problems	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

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

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.[59] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than 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.

Table 4-23 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

Table 4-23 PJM EFORd, XEFORd and EFORp data by unit type: January through March, 2013[60]

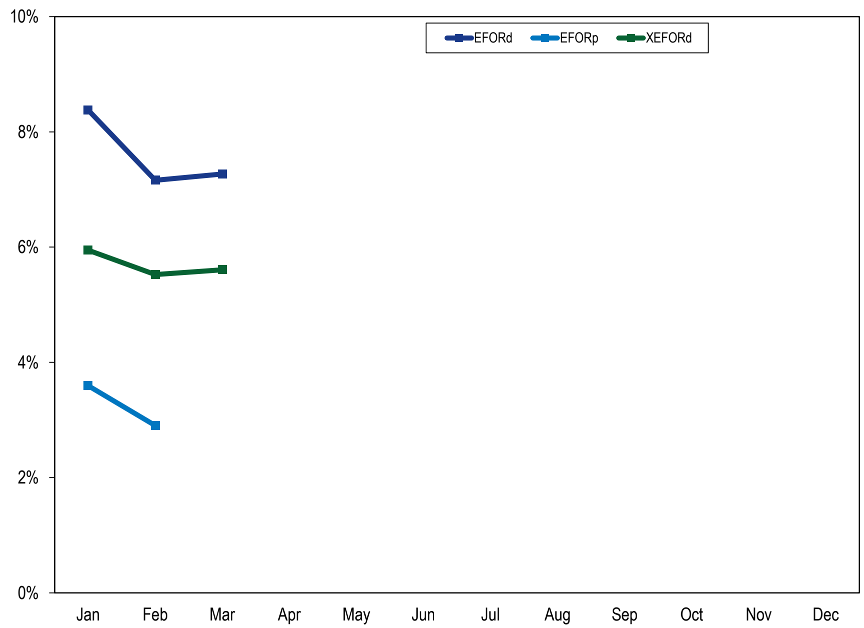
				Difference	Difference
	EFORd	XEFORd	EFORp	EFORd and XEFORd	EFORd and EFORp
Combined Cycle	5.4%	4.5%	1.6%	0.9%	3.8%
Combustion Turbine	18.3%	12.6%	5.7%	5.7%	12.5%
Diesel	3.4%	3.0%	1.4%	0.5%	2.0%
Hydroelectric	0.6%	0.6%	0.5%	0.1%	0.1%
Nuclear	0.5%	0.5%	0.6%	0.0%	(0.1%)
Steam	9.5%	7.4%	5.0%	2.1%	4.5%
Total	**8.3%**	**6.3%**	**3.7%**	**2.0%**	**4.7%**

57 The classification and definitions of these outages are defined by NERC GADS.
58 The classification and definitions of these outages are defined by NERC GADS.
59 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.
60 EFORp is only calculated for the peak months of January, February, June, July, and August.

Performance By Month

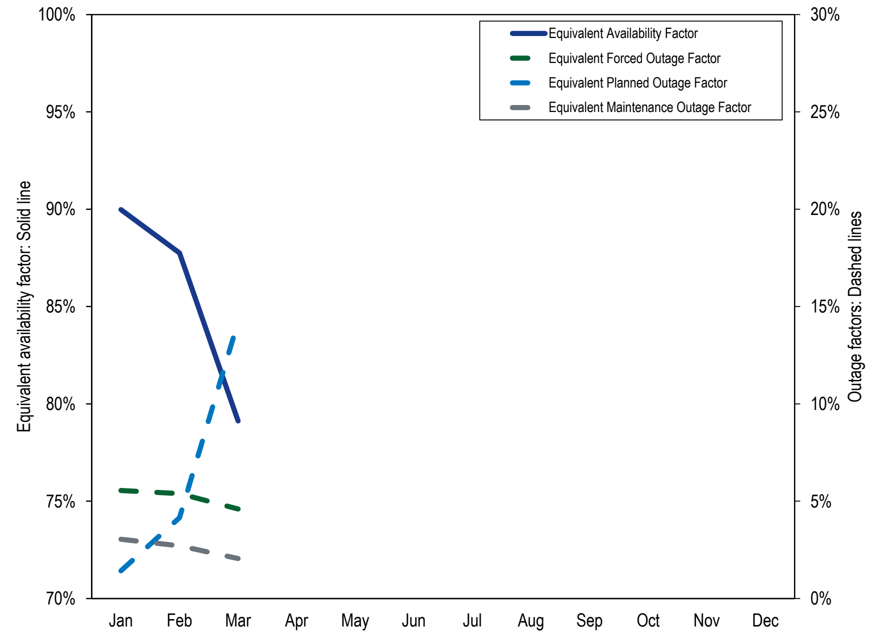
On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-9, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

Figure 4-9 PJM EFORd, XEFORd and EFORp: January through March, 2013



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 4-10.

Figure 4-10 PJM monthly generator performance factors: January through March, 2013



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 the first three months of 2013, total load reduction under the Economic Load Response Program increased by 12,936 MWh compared to the same period in 2012, from 1,030 MWh in the first three months of 2012 to 13,966 MWh in the first three months of 2013, a 1,256 percent increase. Total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013, a 2,170 percent increase.

  Settled reductions and credits were greater in the first three months of 2013 compared to 2012. Participation levels increased following the implementation of Order No. 745, on April 1, 2012, allowing payment of full LMP for demand resources.

  Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In the first three months of 2013, Load Management (LM) Program revenues revenue decreased $38.4 million, or 36.8 percent, from $104 million to $66 million. Through the first three months of 2013, Synchronized Reserve credits for demand side resources decreased by $0.6 million compared to the same period in 2012, from $1.3 million to $0.7 million in 2013.

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.

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 are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[1]

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.[2]

1 For additional conclusions see the *2012 State of the Market Report for PJM*, Section 5, "Demand Response."

2 For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.

Table 5-1 Overview of Demand Side Programs[3]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM;	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched 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 full LMP. Energy payment for hours of dispatched curtailment.

Participation in Demand Side Programs

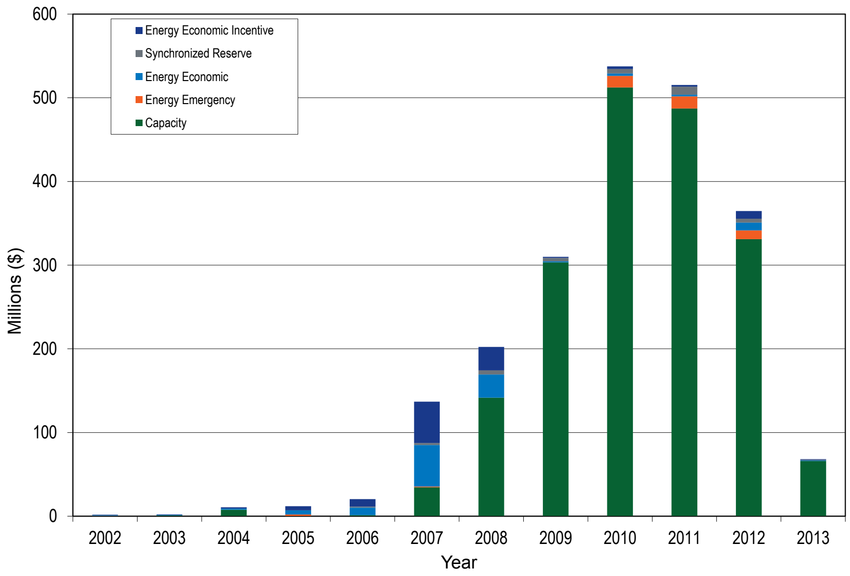
On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first three months of 2013, in the Economic Program, participation increased compared to the same period in 2012. There were more settlements submitted and active registrations in 2013 compared to the same period in 2012, and credits increased.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first three months of 2013. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 97.91 percent of all revenue received through demand response programs in the first three months of 2013. In the first three months of 2013, total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013. This represents a 2,170 percent increase in payments, but still only 1.0 percent of all revenue received through PJM demand response programs. In the first quarter of 2013, capacity revenue represents 97.9 percent of all revenue received by demand response providers, emergency energy revenue represented 0.0 percent, revenue from the economic program represented 1.0 percent and revenue from Synchronized Reserve represented 1.1 percent.

Capacity revenue decreased by $38.4 million, or 36.8 percent, from $104.3 million to $66.0 million in the first three months of 2013, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $0.6 million, from $1.3 million to $0.7 million in the first three months 2013, due to lower clearing prices in the Synchronized Reserve market.

3 Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

Figure 5-1 Demand Response revenue by market: 2002 through March 2013



Economic Program

Table 5-2 shows registered sites and MW for the last day of each month for the period 2010 through the first three months of 2013.[4] The average registered MW for the first three months decreased by 131 MW from 2,375 in 2012 to 2,244 registered MW in 2013. The overall credits paid by the Economic program increased to $690,229 in the first three months of 2013 from $30,406 in the same period of 2012. Historically, registered MW have 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. Registrations in January through March 2013 were 1,171 less than 2012. The average amount of active registrations was 1,995 in the first three months of 2012 and 824 in the same period in 2013.

Total payments in Table 5-3 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[5]

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2009 through March 2013. Lower energy prices and growth in the capacity market program resulted in reduced incentives to participate. Energy prices declined significantly in 2009, and have remained low through the first three months of 2013.[6] In the first three months of 2013, credits were up substantially compared to 2012, following the implementation of Order No. 745 on April 1, 2012. February of 2013 showed the highest credits paid in a month since 2009. The credits paid to economic demand response participants were $175,145 in February of 2009 and increased by $97,857 to $273,002 in 2013. Participation has increased since the implementation of Order 745 in the first three months of 2013 compared to the same period of 2012, both in MWh and number of registrations. The data for March 2013 do not reflect total activity because participants have up to 60 days to submit data for settlement.

4 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.

5 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 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

6 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.

Table 5-2 Economic Program registrations on the last day of the month: 2010 through March 2013

	2010		2011		2012		2013	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,250
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,262
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,219
Apr	1,849	2,587	1,611	2,534	189	1,318		
May	1,875	2,819	1,687	3,166	371	1,669		
Jun	813	1,608	1,143	1,912	803	2,347		
Jul	1,192	2,159	1,228	2,062	942	2,323		
Aug	1,616	2,398	1,987	2,194	1,013	2,373		
Sep	1,609	2,447	1,962	2,183	1,052	2,421		
Oct	1,606	2,444	1,954	2,179	828	2,269		
Nov	1,605	2,444	1,988	2,255	824	2,267		
Dec	1,598	2,439	1,992	2,259	846	2,283		
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	824	2,244

Table 5-3 Performance of PJM Economic Program participants excluding incentive payments: 2003 through March 2013

	Total MWh	Total Payments	$/MWh
2003	19,518	$833,530	$42.71
2004	58,352	$1,917,202	$32.86
2005	157,421	$13,036,482	$82.81
2006	258,468	$10,213,828	$39.52
2007	714,148	$31,600,046	$44.25
2008	452,222	$27,087,495	$59.90
2009	57,157	$1,389,136	$24.30
2010	74,070	$3,088,049	$41.69
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	13,966	$690,229	$49.42

Figure 5-2 Economic Program payments by month: 2009 through March 2013

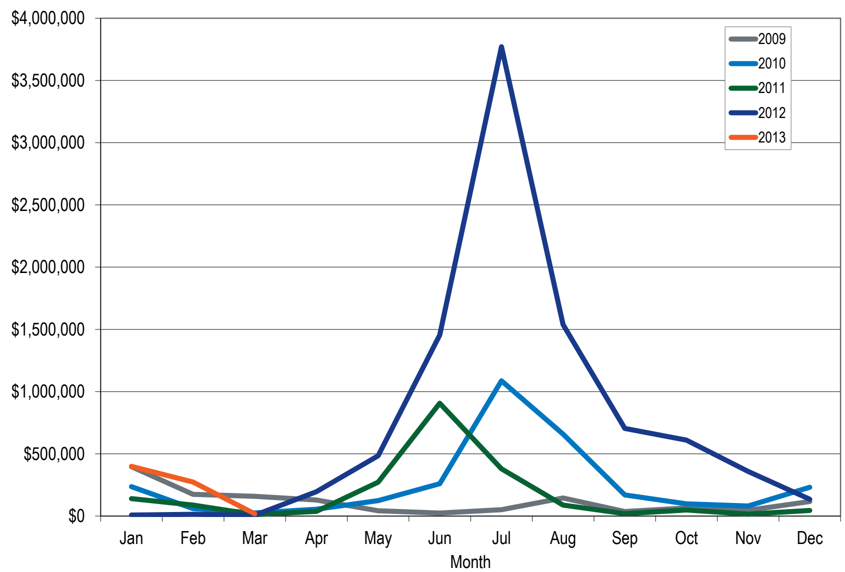


Table 5-4 shows the first three months of 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 13,966 MWh and the total payment amount was $690,229.[7] The Dominion Control Zone accounted for $590,714 or 86 percent of all Economic Program credits, associated with 12,155 or 87 percent of total program MWh reductions. Table 5-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion has the highest average MW reductions per customer and average credits per customer. Since the implementation of Order No. 745 on April 1, 2012, credits have increased. Credits for the first three months of 2013 increased by $659,823 or 2,170 percent compared to the same time period of 2012.

Table 5-4 PJM Economic Program participation by zone: January through March 2012 and 2013

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$0	$0	NA	0	0	NA
AEP	$0	$818	NA	0	17	NA
AP	$0	$9,001	NA	0	290	NA
ATSI	$0	$107	NA	0	3	NA
BGE	$0	$24,717	NA	0	134	NA
ComEd	$0	$25,435	NA	0	722	NA
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$0	NA	0	0	NA
DLCO	$0	$0	NA	0	0	NA
Dominion	$29,862	$590,714	1,878%	1,010	12,155	1,104%
DPL	$0	$0	NA	0	0	NA
JCPL	$0	$0	NA	0	0	NA
Met-Ed	$133	$727	448%	4	9	128%
PECO	$412	$6,619	1,508%	17	82	395%
PENELEC	$0	$16,177	NA	0	198	NA
Pepco	$0	$0	NA	0	0	NA
PPL	$0	$11,605	NA	0	222	NA
PSEG	$0	$4,309	NA	0	134	NA
RECO	$0	$0	NA	0	0	NA
Total	$30,406	$690,229	2,170%	1,030	13,966	1,256%

7 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

Table 5-5 shows total settlements submitted by month for 2008 through March 2013.

Table 5-5 Settlement days submitted by month in the Economic Program: 2008 through March 2013

Month	2008	2009	2010	2011	2012	2013
Jan	2,916	1,264	1,415	562	62	192
Feb	2,811	654	546	148	30	92
Mar	2,818	574	411	82	46	126
Apr	3,406	337	338	102	93	
May	3,336	918	673	298	144	
Jun	3,184	2,727	1,221	743	1,477	
Jul	3,339	2,879	3,010	1,412	2,899	
Aug	3,848	3,760	2,158	793	1,681	
Sep	3,264	2,570	660	294	555	
Oct	1,977	2,361	699	66	481	
Nov	1,105	2,321	672	51	280	
Dec	986	1,240	894	40	124	
Total	32,990	21,605	12,697	4,591	7,872	410

Table 5-6 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2009 through March 2013.[8] The number of active customers during the first three months of 2013 increased by 30 compared to the same period in 2012.

8 February and March 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.

Table 5-6 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2009 through March 2013

	2009		2010		2011		2012		2013	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	17	257	11	153	5	40	5	15	8	47
Feb	12	129	9	92	6	29	3	9	5	14
Mar	11	149	7	124	3	15	3	12	5	19
Apr	9	76	5	77	3	15	3	8		
May	9	201	6	140	6	144	5	20		
Jun	20	231	11	152	10	304	16	338		
Jul	21	183	18	267	15	214	21	383		
Aug	15	400	14	317	14	186	17	361		
Sep	11	181	11	96	7	47	11	127		
Oct	11	93	8	37	3	9	9	50		
Nov	9	143	7	38	3	13	5	63		
Dec	10	160	7	44	5	12	3	10		
Total Distinct Active	25	747	24	438	20	610	24	520	10	53

Table 5-7 Hourly frequency distribution of Economic Program MWh reductions and credits: January through March 2013

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	8	0.06%	8	0.06%	$91	0.01%	$91	0.01%
2	6	0.04%	14	0.10%	($117)	(0.02%)	($26)	(0.00%)
3	6	0.04%	20	0.14%	($40)	(0.01%)	($66)	(0.01%)
4	6	0.04%	26	0.18%	$174	0.03%	$108	0.02%
5	10	0.07%	36	0.26%	$239	0.03%	$347	0.05%
6	13	0.09%	49	0.35%	$404	0.06%	$751	0.11%
7	2,096	15.01%	2,145	15.36%	$109,162	15.82%	$109,913	15.92%
8	2,351	16.83%	4,496	32.20%	$148,627	21.53%	$258,540	37.46%
9	2,187	15.66%	6,683	47.85%	$108,468	15.71%	$367,009	53.17%
10	1,931	13.83%	8,614	61.68%	$81,826	11.85%	$448,834	65.03%
11	1,350	9.67%	9,964	71.35%	$57,456	8.32%	$506,290	73.35%
12	1,064	7.62%	11,028	78.97%	$41,690	6.04%	$547,980	79.39%
13	605	4.33%	11,634	83.30%	$23,643	3.43%	$571,623	82.82%
14	373	2.67%	12,007	85.97%	$14,900	2.16%	$586,523	84.98%
15	209	1.50%	12,216	87.47%	$7,263	1.05%	$593,786	86.03%
16	262	1.87%	12,478	89.35%	$9,398	1.36%	$603,184	87.39%
17	258	1.85%	12,736	91.19%	$9,472	1.37%	$612,657	88.76%
18	263	1.88%	12,999	93.08%	$11,280	1.63%	$623,937	90.40%
19	409	2.93%	13,408	96.00%	$24,179	3.50%	$648,115	93.90%
20	339	2.43%	13,747	98.43%	$24,554	3.56%	$672,670	97.46%
21	156	1.12%	13,902	99.55%	$14,471	2.10%	$687,141	99.55%
22	26	0.19%	13,928	99.73%	$1,116	0.16%	$688,257	99.71%
23	23	0.17%	13,952	99.90%	$813	0.12%	$689,070	99.83%
24	14	0.10%	13,966	100.00%	$1,159	0.17%	$690,229	100.00%

Table 5-7 shows a frequency distribution of MWh reductions and credits at each hour for the first three months of 2013. The period from hour ending 0700 EPT to 1200 EPT accounts for 79 percent of MWh reductions and 79 percent of credits.

Table 5-8 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. MWh reductions in the $0 to $25 bracket increased from 0 MWh in 2012 to 88 MWh in the first three months of 2013. Since these reductions were below the Net Benefits Test, they did not receive any credits for their reduction from the economic program. MWh reductions in the $25 to $50 LMP bracket increased 1,625 percent from 612 MWh to 10,559 MWh in the first three months of 2013.

Total Economic Program reductions increased by 12,785 MWh, from 1,181 MWh in the first three months of 2012 to 13,966 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 89.0 percent of MWh reductions and 74.3 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75.

Following the implementation of Order 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during hours they were dispatched. If the demand resources are cost effective as determined by a Net Benefits Test (NBT), they are eligible to receive the full LMP. The NBT is used to define a threshold point where net benefits of DR are considered to exceed the cost to load. The Net Benefits Test defined an average threshold of $25.86 from January through March 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test threshold.

Table 5-8 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through March 2013

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	88	0.63%	88	0.63%	$0	0.00%	$0	0.00%
$25 to $50	10,559	75.61%	10,647	76.24%	$403,058	58.39%	$403,058	58.39%
$50 to $75	1,876	13.43%	12,523	89.67%	$109,979	15.93%	$513,037	74.33%
$75 to $100	637	4.56%	13,160	94.23%	$54,013	7.83%	$567,050	82.15%
$100 to $125	211	1.51%	13,371	95.74%	$22,658	3.28%	$589,708	85.44%
$125 to $150	299	2.14%	13,670	97.88%	$41,617	6.03%	$631,325	91.47%
$150 to $200	262	1.88%	13,932	99.76%	$49,664	7.20%	$680,989	98.66%
$200 to $250	20	0.14%	13,952	99.90%	$4,304	0.62%	$685,293	99.28%
$250 to $300	2	0.02%	13,954	99.92%	$590	0.09%	$685,884	99.37%
> $300	12	0.08%	13,966	100.00%	$4,346	0.63%	$690,229	100.00%

Load Management Program

Table 5-9 shows zonal monthly capacity credits paid during January through March of 2013 to DR resources. Capacity revenue decreased in the first three months of 2013 by $38.4 million, or 36.8 percent, compared to the first three months of 2012; from 104.3 million to 66.0 million in the same time period of 2013. Credits from January to March are associated with participation in the 2012/2013 RPM delivery year. The decrease in capacity credits in 2013 is the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones to $133.37, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year. The decrease is also related to the end of the ILR program, as well as a decrease in available capacity due to the FERC order ending the ability to count reductions above peak load contribution.[9]

The load management product is currently defined as an emergency product. The Load Management product is an economic product and it is treated as an economic product in the PJM capacity market design. The Load Management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.

9 137 FERC ¶ 61,108

Table 5-9 Zonal monthly capacity credits: January through March 2013

Zone	January	February	March	Total
AECO	$411,097	$371,313	$411,097	$1,193,507
AEP	$425,101	$383,962	$425,101	$1,234,163
AP	$185,478	$167,528	$185,478	$538,484
ATSI	$19,859	$17,937	$19,859	$57,654
BGE	$5,430,108	$4,904,613	$5,430,108	$15,764,828
ComEd	$405,926	$366,643	$405,926	$1,178,494
DAY	$63,670	$57,508	$63,670	$184,848
DEOK	$8,185	$7,393	$8,185	$23,762
DLCO	$49,718	$44,907	$49,718	$144,343
Dominion	$306,929	$277,226	$306,929	$891,084
DPL	$1,547,049	$1,397,335	$1,547,049	$4,491,434
JCPL	$1,495,628	$1,350,890	$1,495,628	$4,342,145
Met-Ed	$1,044,281	$943,222	$1,044,281	$3,031,784
PECO	$2,660,069	$2,402,643	$2,660,069	$7,722,780
PENELEC	$1,144,857	$1,034,064	$1,144,857	$3,323,777
Pepco	$1,906,591	$1,722,082	$1,906,591	$5,535,263
PPL	$3,247,272	$2,933,020	$3,247,272	$9,427,564
PSEG	$2,354,400	$2,126,555	$2,354,400	$6,835,356
RECO	$14,896	$13,454	$14,896	$43,245
Total	$22,721,111	$20,522,294	$22,721,111	$65,964,516

Limited Demand Resource Penalty Charge

Limited Demand Response Resources are required to be available for only 10 times during the months of June through September in a Delivery Year on weekdays other than PJM holidays from 12:00pm to 8:00pm EPT and be capable of maintaining an interruption for 6 hours within a two hour window of PJM starting the event. When a provider under complies based on their registered MW, a penalty occurs based on the amount of under compliance, the number of events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete. The penalties are assessed daily and have increased by $502,446 since December 31, 2012. Table 5-10 shows penalty charges by zone for the 2012/2013 DY. Met-Ed was the only zone that was called for an event that had no penalty charges.

Table 5-10 Penalty Charges per Zone: Delivery Year 2012/2013

	Penalty Charge
AECO	$76.00
AEP	$119,517.60
AP	$0.00
ATSI	$0.00
BGE	$111,479.84
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$49,156.80
DPL	$616,958.88
DLCO	$0.00
JCPL	$4,441.44
Met-Ed	$0.00
PECO	$332,655.04
PENELEC	$36,701.92
Pepco	$417,191.36
PPL	$495.52
PSEG	$8,478.56
RECO	$0.00
Total	$1,697,152.96

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 turbine (CT), combined cycle (CC), coal plant (CP), integrated gasification combined cycle (IGCC), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- In the first three months of 2013, energy market net revenues for a coal plant in seven zones exceeded fifty percent of the 2012 annual energy market net revenues. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.

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

When compared to annualized 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 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. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

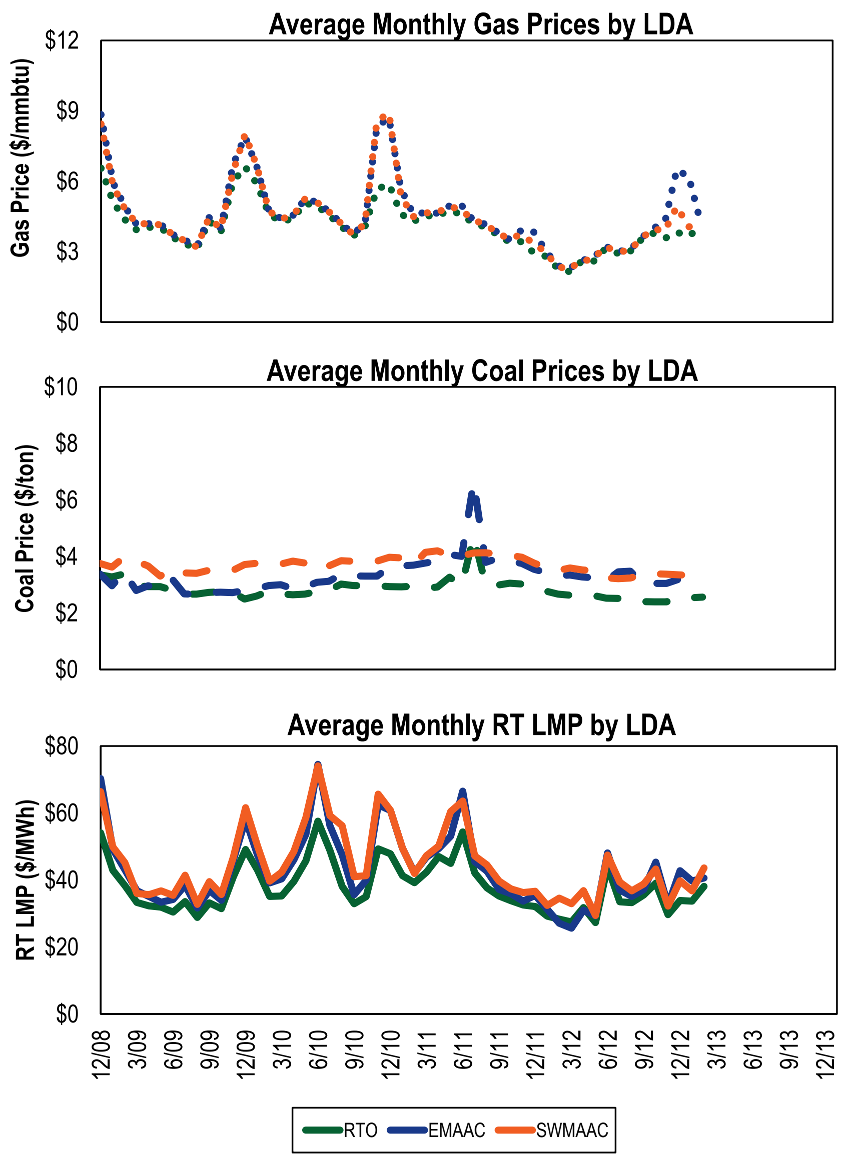
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute 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.

Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time, fuel cost adjusted, load weighted, average LMP for the first three months of 2013 was 8.1 percent higher than the load weighted LMP for the first three months of 2012. Comparing prices in the first three months of 2013 to prices in 2012, the price of Northern Appalachian coal was 2.1 percent lower; the price of Central Appalachian coal was 3.8 percent higher; the price of Powder River Basin coal was 16.5 percent higher; the price of eastern natural gas was 72.2 percent higher; and the price of western natural gas was 28.0 percent higher.

1 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Figure 6-1 Energy Market net revenue factor trends: December 2008 through March 2013



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 this economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes eight power plant configurations:

- 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.[2]
- The CP is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The IGCC plant consists of a coal gasification plant producing a low BTU gas product which is fired in two modified GE Frame 7FA CTs in CC configuration.
- The DS plant consists of one oil fired CAT 2 MW unit using ultra low sulfur fuel.
- The nuclear plant consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology. The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.

2 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.

- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC, CP and IGCC include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[3,4] Plant heat rates were calculated to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[5]

A forced outage rate for each class of plant was calculated from PJM data.[6] This class-specific outage rate was then incorporated into all revenue calculations. Each CT, CC, CP and IGCC 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 are set to zero. Ancillary service revenues for the provision of regulation service for the CT, CC and IGCC plant are also set to zero since these plant types typically do not provide regulation service in PJM. No black start service capability is assumed for any of the unit types.

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.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years. IGCC generators are assumed to receive reactive revenues equal to the CP plant.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] 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.[8] 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.[9]

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.

3 Hourly ambient conditions supplied by Schneider Electric.
4 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.
5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
6 Outage figures obtained from the PJM eGADS database. The CC outage rate was used for the IGCC plant.
7 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.
8 Gas daily cash prices obtained from Platts.
9 Coal prompt prices obtained from Platts.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, 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 costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 6-1 Energy Market net revenue[10] for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through March 2013

Zone	2009	2010	2011	2012	2013 (Jan-Mar)
AECO	$12,421	$40,037	$46,157	$24,993	$3,359
AEP	$3,696	$11,575	$20,839	$16,263	$1,718
AP	$11,136	$32,494	$32,958	$21,029	$3,077
ATSI	NA	NA	NA	$18,296	$1,822
BGE	$15,126	$52,411	$48,642	$36,307	$5,350
ComEd	$2,445	$9,446	$15,081	$13,780	$1,353
DAY	$3,313	$11,701	$21,705	$18,573	$1,416
DEOK	NA	NA	NA	$16,004	$1,159
DLCO	$4,471	$17,525	$24,179	$18,773	$1,748
Dominion	$15,253	$42,922	$38,945	$25,375	$3,937
DPL	$13,886	$40,530	$44,339	$32,587	$3,859
JCPL	$11,994	$39,409	$44,968	$24,117	$5,826
Met-Ed	$11,083	$39,409	$40,802	$25,396	$3,707
PECO	$10,611	$38,311	$45,853	$25,884	$3,383
PENELEC	$6,986	$24,309	$32,090	$22,463	$3,970
Pepco	$17,798	$50,906	$44,233	$32,011	$5,697
PPL	$10,045	$33,649	$42,872	$22,817	$3,497
PSEG	$10,079	$37,626	$37,929	$24,081	$2,650
RECO	$8,717	$35,022	$32,178	$22,808	$5,340
PJM	$9,945	$32,781	$36,104	$23,240	$3,309

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. 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 costs.[11] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 6-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through March 2013

Zone	2009	2010	2011	2012	2013 (Jan-Mar)
AECO	$62,063	$106,643	$126,869	$101,124	$16,489
AEP	$29,759	$47,591	$82,324	$87,908	$17,160
AP	$59,052	$91,032	$113,561	$100,499	$20,252
ATSI	NA	NA	NA	$94,387	$18,367
BGE	$70,571	$124,665	$130,806	$123,367	$21,238
ComEd	$20,613	$33,906	$46,293	$61,754	$8,198
DAY	$27,904	$46,647	$82,067	$93,517	$17,644
DEOK	NA	NA	NA	$82,044	$14,428
DLCO	$27,649	$51,180	$81,642	$89,180	$14,086
Dominion	$68,932	$116,873	$114,530	$103,610	$19,595
DPL	$64,321	$106,245	$123,599	$114,808	$17,887
JCPL	$61,477	$105,474	$124,878	$100,386	$20,197
Met-Ed	$55,400	$97,665	$111,653	$96,018	$15,848
PECO	$57,843	$99,951	$121,804	$98,151	$14,688
PENELEC	$48,876	$80,773	$109,048	$106,236	$24,602
Pepco	$71,959	$121,952	$121,143	$115,691	$21,174
PPL	$52,285	$87,314	$111,111	$91,727	$14,835
PSEG	$57,910	$101,819	$114,951	$96,617	$13,546
RECO	$51,808	$93,724	$96,235	$90,924	$18,349
PJM	$52,260	$89,027	$106,618	$97,260	$17,294

10 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

11 All starts associated with combined cycle units are assumed to be hot starts.

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 day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 6-3 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through March 2013

Zone	2009	2010	2011	2012	2013 (Jan-Mar)
AECO	$87,901	$149,022	$75,325	$23,301	$11,321
AEP	$19,251	$56,227	$72,858	$41,244	$13,288
AP	$49,303	$98,671	$99,020	$54,552	$22,324
ATSI	NA	NA	NA	$47,274	$19,928
BGE	$46,299	$80,689	$56,940	$23,390	$9,476
ComEd	$42,738	$106,599	$94,493	$53,813	$18,182
DAY	$27,905	$77,082	$65,842	$43,027	$22,142
DEOK	NA	NA	NA	$36,519	$18,782
DLCO	$22,971	$76,395	$47,075	$43,904	$14,402
Dominion	$46,756	$144,290	$77,310	$17,547	$12,827
DPL	$38,833	$147,279	$94,908	$29,102	$12,635
JCPL	$74,389	$147,559	$71,437	$30,517	$9,673
Met-Ed	$57,888	$139,228	$61,703	$38,561	$4,643
PECO	$78,602	$142,542	$74,834	$24,474	$10,002
PENELEC	$77,650	$122,426	$95,440	$52,897	$26,551
Pepco	$70,058	$160,627	$73,476	$23,706	$16,388
PPL	$71,601	$114,549	$76,697	$18,079	$8,394
PSEG	$171,879	$124,533	$47,550	$22,590	$24,447
RECO	$71,025	$143,410	$59,111	$29,258	$25,046
PJM	$62,062	$119,478	$73,178	$34,408	$15,813

New Entrant Integrated Gasification Combined Cycle

Energy market net revenue was calculated for an IGCC plant located in the Dominion zone assuming that the IGCC plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Table 6-4 PJM Energy Market net revenue for a new entrant IGCC (Dollars per installed MW-year): 2012 through March 2013

Zone	2012	2013 (Jan-Mar)
Dominion	$13,130	$1,386

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

Table 6-5 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through March 2013

Zone	2013 (Jan-Mar)
AECO	$120
AEP	$4
AP	$45
ATSI	$0
BGE	$388
ComEd	$0
DAY	$0
DEOK	$0
DLCO	$0
Dominion	$210
DPL	$139
JCPL	$116
Met-Ed	$101
PECO	$112
PENELEC	$36
Pepco	$356
PPL	$93
PSEG	$107
RECO	$142
PJM	$0

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant located in the AEP zone was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

Table 6-6 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2012 through March 2013

Zone	2012	2013 (Jan-Mar)
AEP	$201,658	$55,901

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power. Capacity revenue was calculated using a 13 percent capacity factor. Wind net revenues include both production tax credits and RECs.

Table 6-7 PJM Energy Market net revenue for a new entrant wind installation (Dollars per installed MW-year): 2012 through March 2013

Zone	2012	2013 (Jan-Mar)
ComEd	$125,004	$45,590
PENELEC	$127,364	$52,230

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power. Capacity revenue was calculated using a 38 percent capacity factor. Solar net revenues include SRECs.

Table 6-8 PJM Energy Market net revenue for a new entrant solar installation (Dollars per installed MW-year): 2012 through March 2013

Zone	2012	2013 (Jan-Mar)
PSEG	$364,893	$108,489

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) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Cross-State Air Pollution Rule (CSAPR), would if implemented, potentially also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's High Electric Demand Day (HEDD) Rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when 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 had a significant impact on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[2] 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 utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility 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.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[3] EPA has filed a petition for rehearing. While a decision on rehearing is pending, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[4] 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. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and particulate matter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

- **Greenhouse Gas Emissions Rule.** On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated

1 For quantification of the impact on new entrant wind and solar installations, see the *2012 State of the Market Report for PJM*, Section 6, "Net Revenue."

2 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

3 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

4 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708 (January 14, 2013).

June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[5]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey 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 such high energy demand days. New Jersey's HEDD rule,[6] 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.[7]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were $2.80 per ton, above the price floor for 2013.

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. On March 31, 2013, 68.4 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 97.6 percent of coal steam MW had some type of particulate control. NO_x emission controlling technology is used by nearly all fossil fuel unit types, and 91.0 percent of fossil fuel fired capacity in PJM has NO_x emission control technology in place.

5 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
6 N.J.A.C. § 7:27-19.
7 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).

State 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 March 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 2.0 percent of all load served in Ohio, to 10.7 percent of all load served in Maryland. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

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 which is greater than the marginal cost of producing 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 marginal cost of producing minus the credit received for each MWh. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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 formally recognized as part of 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 incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets 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.[8,9] In recent years, the EPA has been actively defining 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 cost 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 rely on 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.[10]

Control of NO_x and SO_2 Emissions Allowances

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.[11] The EPA has sought to promulgate default Federal rules to achieve this objective.[12]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[13] 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. 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 Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[14]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_x, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[15] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The Market Monitoring Unit objected to the proposed rule, as it had to similar provisions

8 42 U.S.C. § 7401 et seq. (2000).
9 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.
10 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."
11 CAA § 110(a)(2)(D)(i)(I).
12 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."
13 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; New Source Performance Standards for Stationary Internal Combustion Engines, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708 (January 14, 2013) ("Final NESHAP RICE Rule").
14 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.
15 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; New Source Performance Standards for Stationary Internal Combustion Engines, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

in a related proposed settlement released for comment, explaining that it was not required for participation by demand side resources in the PJM markets nor for reliability.[16] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[17] Otherwise a 15-hour exception applies.[18] The exempted emergency demand response programs include Demand Resources in RPM.

Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the 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.[19] 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.[20] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[21,22]

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).[23] A settlement in a Federal Court, as modified, obligates the EPA to issue a final rule no later than June 27, 2013.[24,25]

16 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *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).
17 Final NESHAP RICE Rule at 31–24.
18 *Id.* at 31.
19 Massachusetts v. EPA, 549 U.S. 497.
20 *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).
21 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
22 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."
23 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).
24 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, *modified*, Second Amendment to Settlement Agreement among the Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, dated July 17, 2012.
25 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey 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 such high energy demand days. New Jersey's HEDD rule,[26] 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.[27,28]

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI)[29] is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[30,31]

A total of 14 auctions were held for 2009–2011 compliance period allowances, and 16 auctions have been held for 2012–2014 compliance period allowances.

Table 7-1 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional 17 auctions held only for the 2012-2014 compliance period held as of December 31, 2012.

26 N.J.A.C. § 7:27-19.
27 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).
28 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."
29 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.
30 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 was implemented 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.
31 For more details see the *2012 State of the Market Report for PJM*, Section 7, "Environmental and Renewables."

Prices for auctions held in the first three months of 2013 for the 2012-2014 compliance period were \$2.80 per allowance (equal to one ton of CO_2), which is above the current price floor for RGGI auctions. The average spot price the first three months of 2013 for a 2012-2014 compliance period allowance was \$2.59 per ton. Monthly average spot prices for the 2012-2014 compliance period ranged from \$1.99 per ton in February to \$3.00 per ton in March.

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In the first three months of 2013, NO_x prices were 0.9 percent lower than in 2012. SO_2 prices were 16.5 percent lower in the first three months of 2013 than in 2012. 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 and Maryland.

Figure 7-1 Spot monthly average emission price comparison: 2012 and 2013

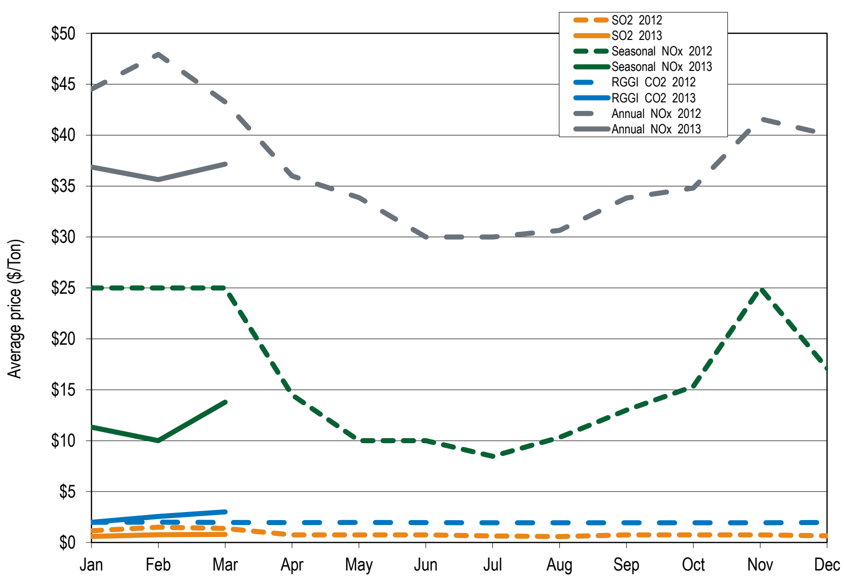


Table 7-1 RGGI CO_2 allowance auction prices and quantities (tons): 2009-2011 and 2012-2014 Compliance Periods[32]

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
March 14, 2012	\$1.93	34,843,858	21,559,000
June 6, 2012	\$1.93	36,426,008	20,941,000
September 5, 2012	\$1.93	37,949,558	24,589,000
December 5, 2012	\$1.93	37,563,083	19,774,000
March 13, 2013	\$2.80	37,835,405	37,835,405

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 March 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 2.0 percent of all load served in Ohio, to 10.7 percent of all load served in Maryland. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2023. As shown in Table 7-2, New Jersey will require 22.5 percent of load to be served by renewable resources in

32 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results>.

2023, 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).

Table 7-2 Renewable standards of PJM jurisdictions to 2023[33,34]

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%	20.00%
Michigan	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%	22.50%
North Carolina	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%
Ohio	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%
Pennsylvania	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%
Washington, D.C.	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%
West Virginia			10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%

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 formally 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.

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 7-2 but must be met by solar RECs (SRECs) 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 2023.[35] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2013, the most stringent standard in PJM was New Jersey's, requiring 0.75 percent of load to be served by solar resources. As Table 7-3 shows, by 2023, the most stringent standard will be New Jersey's which requires at least 3.65 percent of load to be served by solar.

33 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
34 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.
35 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

Table 7-3 Solar renewable standards of PJM jurisdictions to 2023

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%
North Carolina	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%
Pennsylvania	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%
West Virginia	No Solar Standard										

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 7-4 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, with 5.25 percent of load served in 2013 and escalating to 15.38 percent in 2023. Maryland, New Jersey, Pennsylvania,[36] 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 3,433 GWh of solar generation by 2023 (Table 7-4).

Table 7-4 Additional renewable standards of PJM jurisdictions to 2023

Jurisdiction		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Illinois	Wind Requirement	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	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)	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%

PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an 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 $641 per MWh.[37] 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 7-5 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.

36 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.

37 See "New Jersey Renewables Portfolio Standard" <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed March 7, 2013).

Table 7-5 Renewable alternative compliance payments in PJM jurisdictions: 2013

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$2.16		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$641.00
North Carolina	No specific penalties		
Ohio	$45.00		$350.00
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 7-6 Renewable generation by jurisdiction and renewable resource type (GWh): January through March, 2013

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	14.9	0.0	0.0	0.0	0.0	0.0	0.0	14.9	29.9
Illinois	36.8	0.0	0.0	0.0	0.0	0.0	1,829.8	1,866.6	1,866.6
Indiana	0.0	0.0	12.1	0.0	0.0	0.0	912.3	924.4	924.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	26.9	0.0	578.4	11.0	144.7	0.0	113.4	729.7	874.4
Michigan	6.4	0.0	15.9	0.0	0.0	0.0	0.0	22.2	22.2
New Jersey	81.8	102.5	8.2	42.5	339.3	0.0	2.5	135.0	576.8
North Carolina	0.0	0.0	153.7	0.0	0.0	0.0	0.0	153.7	153.7
Ohio	86.2	0.0	120.8	0.2	0.0	0.0	350.5	557.8	557.8
Pennsylvania	213.9	333.9	689.8	4.3	356.8	2,385.2	1,044.3	1,952.3	5,028.1
Tennessee	0.0	0.0	0.0	0.0	78.0	0.0	0.0	0.0	78.0
Virginia	92.4	985.4	228.2	1.9	272.3	0.0	0.0	322.5	1,580.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	1.7	0.0	348.0	0.0	0.0	267.6	535.2	884.9	1,152.5
Total	561.1	1,421.7	2,155.0	59.8	1,191.0	2,652.7	4,788.1	7,564.0	12,829.5

Table 7-6 shows generation by jurisdiction and renewable resource type in the first three months of 2013. This includes only units that would 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 4,788.1 GWh of 7,564.0 Tier I GWh, or 63.3 percent, in the PJM footprint. As shown in Table 7-6, 12,829.5 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 59.0 percent.

Table 7-7 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[38] This capacity 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. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 25.3 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 186.1 MW, or 75.1 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,707.6 MW, or 56.6 percent of the total wind capacity.

38 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 7-7 PJM renewable capacity by jurisdiction (MW), on March 31, 2013

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	1,865.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,887.2
Illinois	0.0	76.8	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,454.4	2,551.2
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,253.2	1,261.4
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	28.7	129.0	31.9	0.0	581.0	40.1	109.0	0.0	120.0	1,099.8
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	186.8	189.1	0.0	7.5	873.9
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	6,578.5	52.3	670.5	225.0	0.0	178.0	1.1	0.0	0.0	500.0	8,205.4
Pennsylvania	35.0	222.0	2,370.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,867.7
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	121.6	80.0	16.9	3,588.0	457.1	2.7	215.0	600.0	0.0	5,081.3
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	15,212.5	601.8	5,565.5	287.6	5,493.0	2,481.5	248.8	924.1	2,152.2	6,549.2	39,516.1

Table 7-8 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not resources offered into PJM wholesale markets. This includes solar capacity of 1,232.3 MW of which 802.8 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 7-8 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.

Table 7-8 Renewable capacity by jurisdiction, non-PJM units registered in GATS[39,40] (MW), on March 31, 2013

Jurisdiction	Coal	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	0.0	46.0	0.0	2.1	48.1
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	60.0
Illinois	0.0	6.6	100.4	0.0	0.0	0.0	34.4	0.0	302.5	443.9
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.1	0.0	0.0	729.9
Kentucky	0.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	106.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	90.0	1.2	0.3	98.5
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	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	0.0	146.0	146.0
New Jersey	0.0	0.0	39.9	0.0	0.0	23.3	802.8	0.0	20.4	886.4
New York	0.0	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0
Ohio	0.0	1.0	41.4	52.6	67.0	1.0	72.6	109.3	15.9	360.8
Pennsylvania	0.0	35.9	29.6	4.8	87.0	0.3	167.9	0.0	3.2	328.6
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.8	318.1	0.0	351.3
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0	1.4
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	0.0	6.6
Total	55.0	170.7	300.3	57.4	833.1	24.6	1,232.3	621.2	490.5	3,785.1

39 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.
40 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed April 01, 2013).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. Many PJM units burning fossil fuels have installed emission control technology.

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 79,345.8 MW of coal steam capacity in PJM, 54,259.0 MW of capacity, 68.4 percent, has some form of FGD technology. Table 7-9 shows emission controls by unit type, of fossil fuel units in PJM.[41]

Table 7-9 SO_2 emission controls (FGD) by unit type (MW), as of March 31, 2013

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	54,259.0	25,086.8	79,345.8	68.4%
Combined Cycle	0.0	27,043.5	27,043.5	0.0%
Combustion Turbine	0.0	31,437.2	31,437.2	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	0.0	8,746.6	8,746.6	0.0%
Total	54,259.0	92,676.9	146,935.9	36.9%

NO_x 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 NO_x controls. Of current fossil fuel units in PJM, 133,681.3 MW, or 91.0 percent, of 146,935.9 MW of capacity in PJM, have emission controls for NO_x. Table 7-10 shows NO_x emission controls by unit type of fossil fuel units in PJM. While most units in PJM have NO_x emission controls, many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future NO_x 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 7-10 NO_x emission controls by unit type (MW), as of March 31, 2013

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,588.2	2,757.6	79,345.8	96.5%
Combined Cycle	26,842.5	201.0	27,043.5	99.3%
Combustion Turbine	25,879.8	5,557.4	31,437.2	82.3%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	4,370.8	4,375.8	8,746.6	50.0%
Total	133,681.3	13,254.6	146,935.9	91.0%

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, 77,461.8 MW, 97.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-11 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 7-11 Particulate emission controls by unit type (MW), as of March 31, 2013

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	77,461.8	1,884.0	79,345.8	97.6%
Combined Cycle	0.0	27,043.5	27,043.5	0.0%
Combustion Turbine	0.0	31,437.2	31,437.2	0.0%
Diesel	0.0	362.8	362.8	0.0%
Non-Coal Steam	3,047.0	5,699.6	8,746.6	34.8%
Total	80,508.8	66,427.1	146,935.9	54.8%

41 See "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed April 15, 2013)

Wind Units

Table 7-12 shows the capacity factor of wind units in PJM. In the first three months of 2013, the capacity factor of wind units in PJM was 34.8 percent. Wind units that were capacity resources had a capacity factor of 35.5 percent and an installed capacity of 4,738 MW. Wind units that were classified as energy only had a capacity factor of 33.4 percent and an installed capacity of 1,811 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.[42]

Table 7-12 Capacity[43] factor[44] of wind units in PJM: January through March 2013

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	33.4%	NA	1,811
Capacity Resource	35.4%	245.6%	4,738
All Units	34.8%	245.6%	6,549

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 January, and lowest in February. The highest average hour, 2,688.8 MW, occurred in January, and the lowest average hour, 1,880.2 MW, occurred in February. 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: January through March 2013

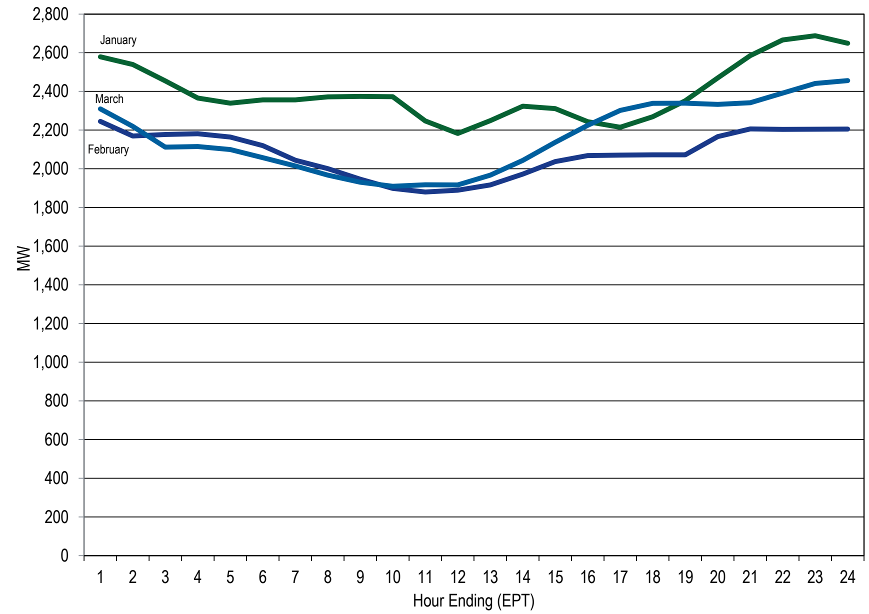


Table 7-13 shows the generation and capacity factor of wind units in each month of 2012 and the first three months of 2013. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 37.7 percent in January, and the lowest capacity factor was 32.7 percent in February. Overall, the capacity factor in winter months is higher than in summer months.

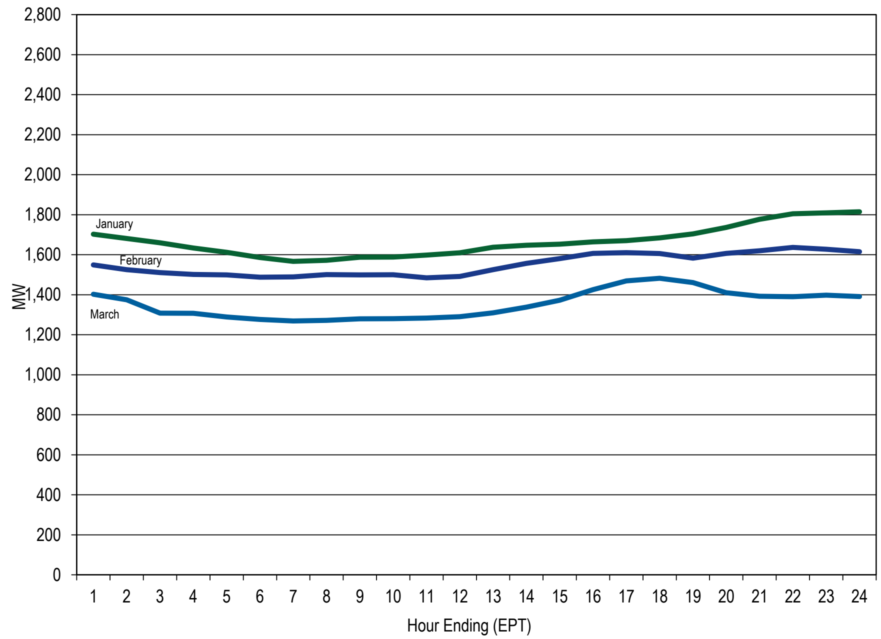
42 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
43 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource.
44 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

Table 7-13 Capacity factor of wind units in PJM by month, 2012 and January through March 2013

Month	2012 Generation (MWh)	Capacity Factor	2013 Generation (MWh)	Capacity Factor
January	1,608,349.8	41.9%	1,784,359.3	37.7%
February	1,167,011.9	32.4%	1,397,468.3	32.7%
March	1,416,278.0	35.6%	1,606,248.3	34.0%
April	1,345,643.3	34.7%		
May	885,583.1	21.6%		
June	882,597.0	22.2%		
July	546,676.9	13.3%		
August	415,544.2	10.1%		
September	677,039.5	16.9%		
October	1,213,664.0	27.7%		
November	1,022,628.8	22.9%		
December	1,452,588.7	31.1%		
Annual	12,633,605.2	25.7%	4,788,076.0	34.8%

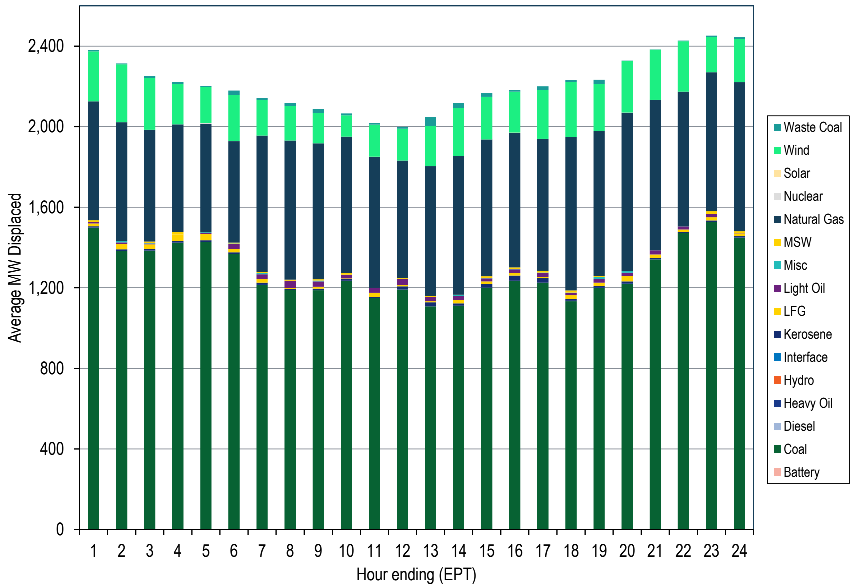
Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 7-3 shows the average hourly day-ahead generation of wind units in PJM, by month.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: January through March 2013



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 2012. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in January through March 2013. Wind output varies daily, and on average is about 455 MW lower from peak average output (2300 EPT) to lowest average output (1100 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.

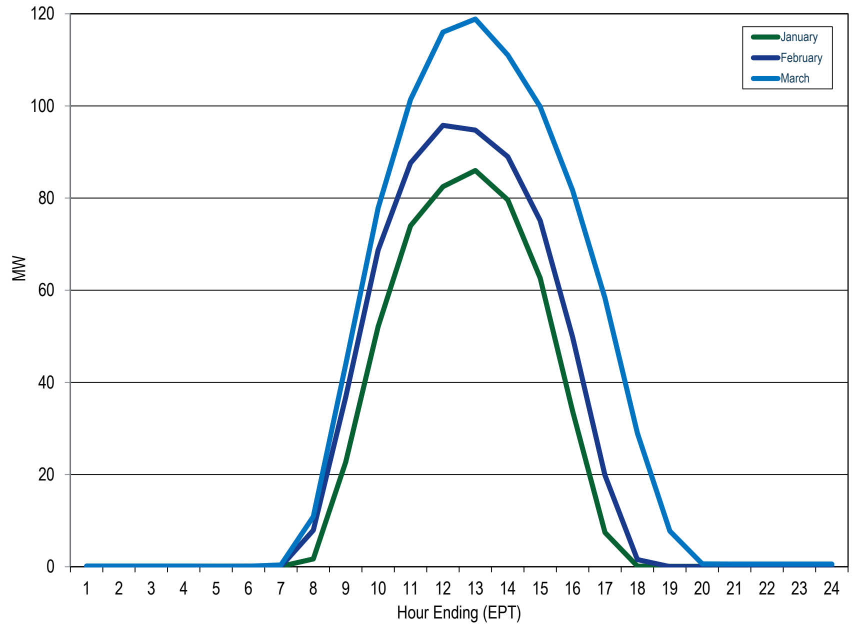
Figure 7-4 Marginal fuel at time of wind generation in PJM: January through March 2013



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 August, the month with the highest average hour, 118.9 MW, compared to 248.8 MW of solar installed capacity in PJM. 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: January through March 2013



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

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[1] During the first three months of 2013, the real-time net interchange of 1,640.5 GWh was greater than net interchange of 800.7 GWh in the first three months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than net interchange of -3,224.6 GWh during the first three months of 2012.

  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 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross import in the Real-Time Energy Market (408.9 percent during the first three months of 2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of the gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[2]

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price

1 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

differentials in only 42.6 percent of hours in the first three months of 2013.

- **PJM and New York ISO Interface Prices.** In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow during the first three months of 2013 was -350 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow during the first three months of 2013 was -188 MW.[6] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013.
- **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 and NYISO. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York. The Hudson DC line is expected to be in service by the end of the second quarter of 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[7] This difference is inadvertent interchange.
- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO.
- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (Figure 8-12).
- **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. On April 12, 2011, the PJM Market Implementation

3 In the first three months of 2013, there were 92 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

4 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

5 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

6 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.

7 The "Net Scheduled" values shown in Table 8-18 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 Table 8-1 through Table 8-6.

Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.[8] These modifications are currently being evaluated by PJM.

- **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. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

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 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.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first three months of 2013, including evolving transaction patterns, economics and issues. 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. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

In the first three months of 2013, 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 57.4 percent of the hours for transactions between PJM and MISO and for 43.8 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to 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 relying 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.

On January 15, 2013, PJM and NYISO implemented the market to market provisions of the PJM/NYISO Joint Operating Agreement (JOA). Coordination between NYISO and PJM includes joint redispatch and coordinated operation of the Ramapo PARs located at the NYISO – PJM interface. The goal of this real-time coordination is a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints.[9]

Loop flows remain a significant concern for the efficiency of the PJM market. 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

8 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>.

9 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[10] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

10 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first three months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in all months (Figure 8-1).[11] During the first three months of 2013, the total real-time net interchange of 1,640.5 GWh was greater than the net interchange of 800.7 GWh during the first three months of 2012. During the first three months of 2013, the peak month for net importing interchange was February, 639.5 GWh; in 2012 it was March, 755.1 GWh. Gross monthly export volumes during the first three months of 2013 averaged 3,202.4 GWh compared to 3,396.8 GWh for the first three months of 2012, while gross monthly imports during the first three months of 2013 averaged 3,749.2 GWh compared to 3,663.7 GWh during the first three months of 2012.

During the first three months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 8-1). During the first three months of 2013, the total day-ahead net interchange of -6,592.7 GWh was greater than the net interchange of -3,224.6 GWh during the first three months of 2012. During the first three months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was January, -1,847.5 GWh. Gross monthly export volumes during the first three months of 2013 averaged 7,790.7 GWh compared to 16,056.3 GWh for the first three months of 2012, while gross monthly imports during the first three months of 2013 averaged 5,593.1 GWh compared to 14,981.4 GWh during the first three months of 2012.

The large decreases in import and export volumes in the Day-Ahead Energy Market were the result of the rule change in November, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).

11 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 8-1 shows the impact of net up-to congestion transactions on the overall net Day-Ahead Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 8-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first three months of 2013, up-to congestion transactions accounted for 73.6 percent of all scheduled import MW transactions, 69.6 percent of all scheduled export MW transactions and 59.4 percent of the net interchange volume in the Day-Ahead Market. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 34,149 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 20,000 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012.

In the first three months of 2013, gross imports in the Day-Ahead Energy Market were 149.2 percent of gross imports in the Real-Time Energy Market (408.9 percent during the first three months of 2012), gross exports in the Day-Ahead Energy Market were 243.3 percent of gross exports in the Real-Time Energy Market (472.7 percent during the first three months of 2012). In the first three months of 2013, net interchange was -6,592.7 GWh in the Day-Ahead Energy Market and 1,640.5 GWh in the Real-Time Energy Market compared to -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market for the first three months of 2012.

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.[12] For the first three months of 2013, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 2013

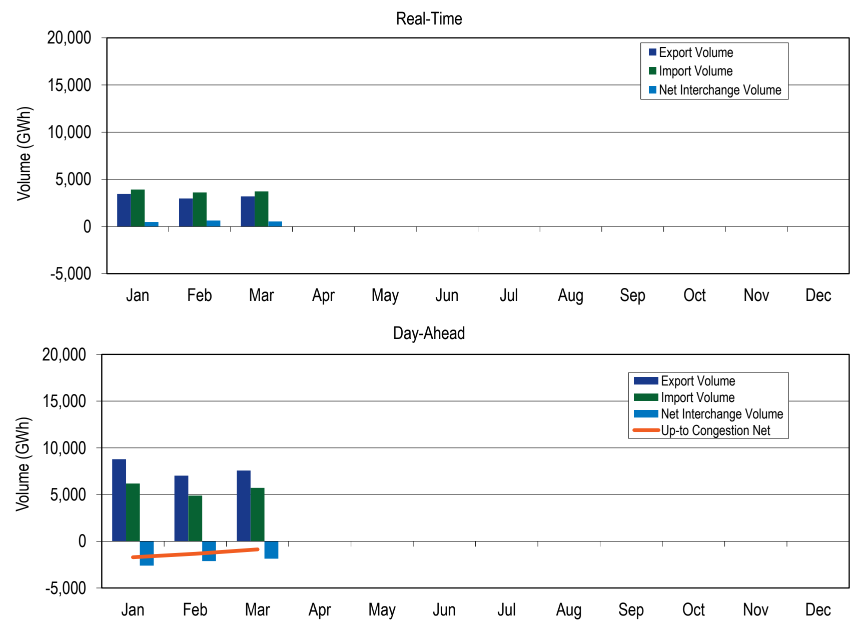


Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through March, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time. The net direction of power flows is generally a result of price differences net of transactions costs. Up-to congestion transactions have played a significant role in power flows between balancing authorities in the Day-Ahead Market since their modification in late 2010.

12 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January through March, 2013

Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is 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 neighboring balancing authorities. See Table 8-16 for a list of active interfaces during the first three months of 2013. Figure 8-3 shows the approximate geographic location of the interfaces. In the first three months of 2013, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all three are interfaces between PJM and the NYISO. Similarly, there are ten separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual NYISO interfaces, 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 the first three months of 2013 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 first three months of 2013, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 65.4 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 34.5 percent, PJM/MidAmerican Energy Company (MEC) with 17.8 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 12.5 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 54.6 percent of the total net PJM exports in the Real-Time Energy Market. Eight PJM interfaces had net scheduled imports, with three importing interfaces accounting for 62.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 28.2 percent, PJM/Tennessee Valley Authority (TVA) with 21.9 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.7 percent of the net import volume.[13]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by 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.[14] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

13 In the Real-Time Market, two PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/western portion of Carolina Power & Light Company (CPLW)).
14 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed May 6, 2013).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	(30.6)	(38.3)	(48.4)	(117.3)
CPLW	0.0	0.0	0.0	0.0
DUK	175.2	122.7	148.1	446.0
EKPC	(149.7)	(139.9)	(152.7)	(442.3)
LGEE	281.5	272.0	302.2	855.7
MEC	(484.1)	(390.8)	(158.9)	(1,033.8)
MISO	283.1	518.3	572.6	1,374.1
ALTE	(306.7)	(176.9)	(239.3)	(723.0)
ALTW	(9.0)	(4.5)	(3.0)	(16.5)
AMIL	181.7	153.6	181.5	516.8
CIN	253.3	285.4	349.7	888.3
CWLP	0.0	0.0	0.0	0.0
IPL	(43.4)	48.1	63.8	68.5
MECS	322.3	298.9	322.5	943.6
NIPS	(22.9)	(12.5)	(22.0)	(57.4)
WEC	(92.1)	(73.8)	(80.5)	(246.4)
NYISO	(1,047.1)	(1,018.0)	(1,100.9)	(3,166.0)
LIND	(165.2)	(149.8)	(91.6)	(406.7)
NEPT	(270.9)	(245.9)	(239.2)	(756.0)
NYIS	(611.0)	(622.3)	(770.1)	(2,003.3)
OVEC	798.2	713.5	585.0	2,096.7
TVA	643.8	600.0	383.6	1,627.4
Total	470.4	639.5	530.6	1,640.5

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	1.4	0.1	1.6	3.0
CPLW	0.0	0.0	0.0	0.0
DUK	225.0	190.6	157.0	572.7
EKPC	4.4	1.5	25.6	31.5
LGEE	299.0	272.4	302.2	873.6
MEC	0.2	48.2	320.6	369.1
MISO	1,026.7	971.1	1,110.5	3,108.2
ALTE	0.0	1.1	0.0	1.1
ALTW	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	599.3
CIN	374.5	394.7	455.5	1,224.7
CWLP	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	274.0
MECS	349.1	321.6	338.3	1,009.0
NIPS	0.2	0.0	0.0	0.2
WEC	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	2,473.8
LIND	0.6	10.4	7.5	18.5
NEPT	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	2,455.3
OVEC	798.3	713.5	585.1	2,096.9
TVA	689.8	630.0	399.1	1,718.9
Total	3,915.7	3,609.5	3,722.4	11,247.6

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	31.9	38.4	50.0	120.3
CPLW	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	126.6
EKPC	154.0	141.4	178.3	473.8
LGEE	17.5	0.4	0.0	17.9
MEC	484.4	439.0	479.6	1,403.0
MISO	743.5	452.8	537.9	1,734.1
ALTE	306.7	178.0	239.3	724.1
ALTW	9.0	4.5	3.0	16.5
AMIL	25.3	23.5	33.6	82.4
CIN	121.2	109.3	105.8	336.4
CWLP	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	205.5
MECS	26.8	22.7	15.8	65.3
NIPS	23.0	12.5	22.0	57.5
WEC	92.1	73.8	80.5	246.4
NYISO	1,918.1	1,800.1	1,921.6	5,639.8
LIND	165.8	160.3	99.1	425.2
NEPT	270.9	245.9	239.2	756.0
NYIS	1,481.5	1,393.9	1,583.3	4,458.7
OVEC	0.1	0.0	0.0	0.1
TVA	46.0	30.0	15.6	91.6
Total	3,445.3	2,970.0	3,191.9	9,607.1

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 scheduled imports or exports will flow.[15] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a 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 MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. 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.[16]

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.[17] 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 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.[18] 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. Table 8-17 presents the interface pricing points used for the first three months of 2013.

15 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.

16 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

17 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed May 6, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

18 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 May 6, 2013)

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 by PJM only occasionally.

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. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

Real-Time Energy Market transaction prices are determined based on transaction details.[19]

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.[20]

In the Real-Time Energy Market, for the first three months of 2013, there were net scheduled exports at ten of PJM's 16 interface pricing points eligible for real-time transactions.[21] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 68.0 percent of the total net exports: PJM/MISO with 38.1 percent, and PJM/NYIS with 29.9 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 48.3 percent of the total net PJM exports in the Real-Time Energy Market. Five PJM interface pricing points had net imports, with two importing interface pricing points accounting for 75.3 percent of the total net imports: PJM/SouthIMP with 48.9 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 26.4 percent of the net import volume.[22]

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	592.6	395.0	556.4	1,543.9
LINDENVFT	(165.2)	(149.8)	(91.6)	(406.7)
MISO	(1,015.3)	(686.3)	(699.3)	(2,400.8)
NEPTUNE	(270.9)	(245.9)	(239.2)	(756.0)
NORTHWEST	(3.6)	(3.3)	(5.9)	(12.8)
NYIS	(603.2)	(572.1)	(706.3)	(1,881.7)
OVEC	798.2	713.5	585.0	2,096.7
SOUTHIMP	1,441.6	1,472.4	1,387.4	4,301.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	107.2	105.3	83.8	296.3
NCMPAIMP	68.6	31.3	19.5	119.5
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	3,885.5
SOUTHEXP	(303.9)	(283.9)	(255.9)	(843.7)
CPLEEXP	(31.3)	(33.4)	(47.6)	(112.3)
DUKEXP	(27.1)	(45.2)	(0.9)	(73.1)
NCMPAEXP	0.0	(0.1)	0.0	(0.1)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(13.1)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(645.1)
Total	470.4	639.5	530.6	1,640.5

19 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.
20 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.
21 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
22 In the Real-Time Market, one PJM interface pricing point had a net interchange of zero (PJM/CPLEIMP).

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	594.6	403.2	562.5	1,560.2
LINDENVFT	0.6	10.4	7.5	18.5
MISO	204.4	196.3	309.1	709.9
NEPTUNE	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0
NYIS	876.3	813.6	870.9	2,560.8
OVEC	798.3	713.5	585.1	2,096.9
SOUTHIMP	1,441.6	1,472.4	1,387.4	4,301.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	107.2	105.3	83.8	296.3
NCMPAIMP	68.6	31.3	19.5	119.5
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	3,885.5
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	3,915.7	3,609.5	3,722.4	11,247.6

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	2.0	8.2	6.1	16.3
LINDENVFT	165.8	160.3	99.1	425.2
MISO	1,219.7	882.6	1,008.4	3,110.7
NEPTUNE	270.9	245.9	239.2	756.0
NORTHWEST	3.6	3.3	5.9	12.8
NYIS	1,479.5	1,385.8	1,577.2	4,442.5
OVEC	0.1	0.0	0.0	0.1
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	303.9	283.9	255.9	843.7
CPLEEXP	31.3	33.4	47.6	112.3
DUKEXP	27.1	45.2	0.9	73.1
NCMPAEXP	0.0	0.1	0.0	0.1
SOUTHWEST	4.5	5.7	3.0	13.1
SOUTHEXP	241.0	199.6	204.5	645.1
Total	3,445.3	2,970.0	3,191.9	9,607.1

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. 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 could be supported in the Real-Time Energy Market.[23] 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 unless they are also submitted in the Real-Time Energy Market. 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.

23 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.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[24]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. 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 bear any necessary relationship to 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 Day-Ahead Market. In the interface tables, 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 totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first three months of 2013 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eleven of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 81.9 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 37.5 percent, PJM/MidAmerican Energy Company (MEC) with 28.5 percent, and PJM/NEPT with 15.9 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 54.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The ten separate interfaces that connect PJM to MISO together represented 7.0 percent of the total net PJM exports in the Day-Ahead Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 84.9 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 65.7 percent, PJM/DUK with 10.0 percent and PJM/Louisville Gas and Electric (LGEE) with 9.2 percent of the net import volume.[25]

24 See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	(33.4)	(28.5)	(41.2)	(103.2)
CPLW	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	224.0
EKPC	(36.6)	(33.6)	(37.2)	(107.3)
LGEE	58.3	65.8	81.8	205.9
MEC	(483.0)	(435.7)	(477.7)	(1,396.3)
MISO	(242.1)	(52.6)	(48.7)	(343.5)
ALTE	(177.8)	(79.5)	(119.1)	(376.3)
ALTW	(7.6)	(2.5)	0.0	(10.1)
AMIL	8.7	5.2	26.3	40.2
CIN	7.9	45.9	37.1	90.9
CWLP	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	(8.4)
MECS	23.4	45.8	102.9	172.2
NIPS	(22.2)	(12.5)	(21.5)	(56.2)
WEC	(73.7)	(49.2)	(72.8)	(195.7)
NYISO	(833.6)	(874.4)	(944.3)	(2,652.3)
LIND	(15.3)	(14.3)	(2.6)	(32.2)
NEPT	(278.5)	(255.2)	(248.7)	(782.5)
NYIS	(539.7)	(604.9)	(693.0)	(1,837.6)
OVEC	561.5	494.4	408.0	1,463.9
TVA	32.7	3.6	(3.6)	32.7
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(2,676.2)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(3,916.5)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(6,592.7)

25 In the Day-Ahead Market, two PJM interface had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	0.0	0.0	0.0	0.0
CPLW	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	224.0
EKPC	0.0	0.0	0.0	0.0
LGEE	58.3	65.8	81.8	205.9
MEC	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	387.0
ALTE	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	40.2
CIN	21.5	64.2	58.4	144.1
CWLP	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	5.6
MECS	39.3	45.8	111.9	197.1
NIPS	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	2,094.3
LIND	0.1	9.3	2.9	12.3
NEPT	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	2,082.1
OVEC	561.5	494.4	408.0	1,463.9
TVA	41.7	13.6	3.6	58.9
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	4,434.0
Up-To Congestion	4,637.9	3,481.0	4,226.5	12,345.4
Total	6,178.8	4,890.5	5,710.0	16,779.3

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2013

	Jan	Feb	Mar	Total
CPLE	33.4	28.5	41.2	103.2
CPLW	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0
EKPC	36.6	33.6	37.2	107.3
LGEE	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	1,396.3
MISO	317.3	167.9	245.4	730.5
ALTE	177.8	79.5	119.1	376.3
ALTW	7.6	2.5	0.0	10.1
AMIL	0.0	0.0	0.0	0.0
CIN	13.7	18.3	21.3	53.3
CWLP	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	14.0
MECS	15.9	0.0	9.1	24.9
NIPS	22.2	12.5	21.5	56.2
WEC	73.7	49.2	72.8	195.7
NYISO	1,559.8	1,524.8	1,662.1	4,746.6
LIND	15.4	23.6	5.5	44.5
NEPT	278.5	255.2	248.7	782.5
NYIS	1,265.9	1,246.0	1,407.8	3,919.7
OVEC	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	26.2
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	7,110.2
Up-To Congestion	6,342.6	4,817.7	5,101.5	16,261.8
Total	8,781.6	7,018.2	7,572.2	23,372.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first three months of 2013, up-to congestion transactions accounted for 73.6 percent of all scheduled import MW transactions, 69.6 percent of all scheduled export MW transactions and 59.4 percent of the net interchange volume in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first three months of 2013 in Table 8-10. Up-to congestion transactions by interface pricing point for the first three months of 2013 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14, while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for the first three months of 2013, there were net scheduled exports at eight of PJM's 18 interface pricing points eligible for day-ahead.[26] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 59.3 percent of the total net exports: PJM/NIPSCO with 21.9 percent, PJM/Northwest[27] with 19.9 percent and PJM/SouthEXP with 17.4 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 25.8 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 67.7 percent of the total net imports: PJM/Southeast with 24.0 percent, PJM/SouthIMP with 23.5 percent, and PJM/Ohio Valley Electric Corporation (OVEC) with 20.2 percent of the net import volume.[28]

In the Day-Ahead Market, for the first three months of 2013, up-to congestion transactions had net exports at six of PJM's 18 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 77.3 percent of the total net up-to congestion exports: PJM/NIPSCO with 32.5 percent, PJM/SouthEXP with 24.1 percent and PJM/Southwest with 20.7 percent of the net export up-to congestion volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 4.5 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 4.5 percent). The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market. Six PJM interface pricing points had net up-to congestion imports, with two importing interface pricing points accounting for 71.1 percent of the total net up-to congestion imports: PJM/MISO with 40.8 percent and PJM/Southeast with 30.3 percent of the net import volume.[29]

26 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
27 The Northwest interface pricing point is assigned to external energy transactions that source or sink in balancing authorities located primarily in the Northwest United States and the contiguous region of Canada, and which are not balancing authorities within MISO. Many balancing authorities located in the Western Interconnection receive the Northwest interface pricing point because the DC Tie lines that connect the Eastern Interconnection with the Western Interconnection are located in the Northwest United States.
28 In the Day-Ahead Market, two PJM interface pricing points had a net interchange of zero (PJM/CPLEIMP and PJM/DUKEXP).

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	27.4	235.1	206.5	468.9
LINDENVFT	102.2	14.5	(14.6)	102.1
MISO	192.7	130.5	453.0	776.3
NEPTUNE	(335.1)	(381.7)	(398.9)	(1,115.7)
NIPSCO	(927.2)	(757.5)	(743.5)	(2,428.2)
NORTHWEST	(744.5)	(810.7)	(646.6)	(2,201.8)
NYIS	(662.2)	(576.6)	(506.4)	(1,745.1)
OVEC	254.6	210.5	438.4	903.5
SOUTHIMP	1,255.6	902.5	877.1	3,035.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	22.5	22.0	9.0	53.5
NCMPAIMP	18.3	15.4	14.9	48.6
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	442.8	307.4	302.0	1,052.2
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(4,388.1)
CPLEEXP	(32.4)	(27.8)	(40.7)	(100.8)
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(2.4)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(104.6)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(2,247.7)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(1,932.5)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(6,592.7)

29 In the Day-Ahead Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	(11.9)	189.4	94.5	272.0
LINDENVFT	117.5	28.8	(12.0)	134.3
MISO	500.7	288.8	660.8	1,450.2
NEPTUNE	(56.5)	(126.5)	(150.2)	(333.2)
NIPSCO	(927.2)	(757.5)	(743.5)	(2,428.2)
NORTHWEST	(261.6)	(375.0)	(168.9)	(805.4)
NYIS	(121.9)	25.3	185.7	89.2
OVEC	(306.9)	(281.8)	31.4	(557.2)
SOUTHIMP	1,050.5	694.0	668.9	2,413.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	278.5	136.1	117.7	532.3
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(4,151.4)
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	(49.3)	(28.8)	(26.5)	(104.6)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(2,247.7)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(1,799.0)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(3,916.5)
INTERNAL	22,906.0	23,311.1	27,439.6	73,656.7
Total	21,201.2	21,974.3	26,564.6	69,740.2

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	268.0	322.5	310.8	901.3
LINDENVFT	292.4	210.2	188.5	691.1
MISO	719.6	516.2	809.8	2,045.6
NEPTUNE	127.2	32.2	11.5	170.9
NIPSCO	35.0	17.1	15.0	67.2
NORTHWEST	287.9	214.8	229.9	732.5
NYIS	1,097.0	1,031.5	1,130.2	3,258.7
OVEC	2,096.0	1,643.5	2,137.2	5,876.7
SOUTHIMP	1,255.6	902.5	877.1	3,035.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	22.5	22.0	9.0	53.5
NCMPAIMP	18.3	15.4	14.9	48.6
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	442.8	307.4	302.0	1,052.2
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	6,178.8	4,890.5	5,710.0	16,779.3

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	228.7	276.6	198.9	704.2
LINDENVFT	292.4	200.9	185.5	678.9
MISO	710.9	505.8	772.2	1,988.9
NEPTUNE	127.2	32.2	11.5	170.9
NIPSCO	35.0	17.1	15.0	67.2
NORTHWEST	287.9	214.8	229.9	732.5
NYIS	370.9	388.3	414.4	1,173.6
OVEC	1,534.5	1,151.2	1,730.2	4,416.0
SOUTHIMP	1,050.5	694.0	668.9	2,413.3
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	1,181.6
SOUTHWEST	283.6	231.0	184.8	699.4
SOUTHIMP	278.5	136.1	117.7	532.3
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	4,637.9	3,481.0	4,226.5	12,345.4

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	240.6	87.4	104.4	432.3
LINDENVFT	190.2	195.7	203.1	589.0
MISO	526.9	385.6	356.8	1,269.3
NEPTUNE	462.2	413.9	410.4	1,286.6
NIPSCO	962.3	774.6	758.5	2,495.4
NORTHWEST	1,032.4	1,025.5	876.4	2,934.3
NYIS	1,759.2	1,608.1	1,636.5	5,003.8
OVEC	1,841.4	1,433.0	1,698.8	4,973.2
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,766.4	1,094.4	1,527.3	4,388.1
CPLEEXP	32.4	27.8	40.7	100.8
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	2.4
SOUTHEAST	49.3	28.8	26.5	104.6
SOUTHWEST	912.1	535.5	800.2	2,247.7
SOUTHEXP	771.5	501.6	659.5	1,932.5
Total	8,781.6	7,018.2	7,572.2	23,372.0

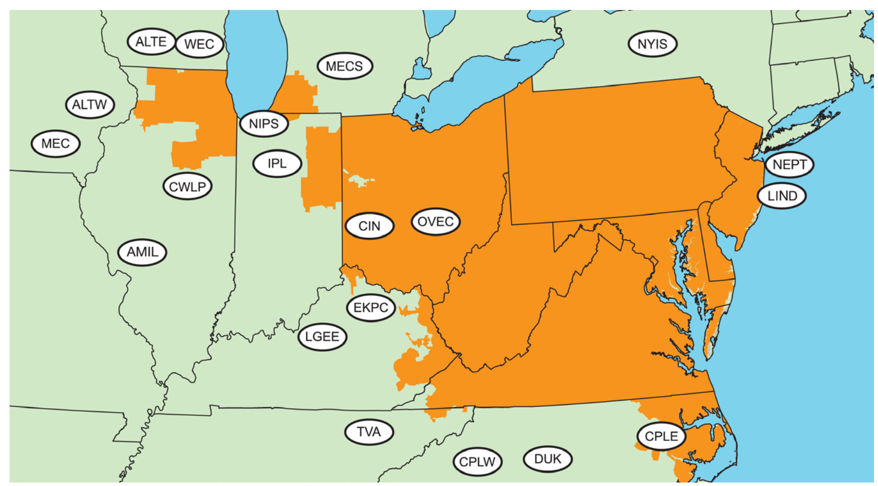
Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2013

	Jan	Feb	Mar	Total
IMO	240.6	87.3	104.4	432.2
LINDENVFT	174.8	172.1	197.6	544.5
MISO	210.2	217.0	111.4	538.7
NEPTUNE	183.7	158.7	161.7	504.1
NIPSCO	962.3	774.6	758.5	2,495.4
NORTHWEST	549.4	589.8	398.7	1,538.0
NYIS	492.8	362.9	228.7	1,084.4
OVEC	1,841.4	1,433.0	1,698.8	4,973.2
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	1,687.4	1,022.2	1,441.8	4,151.4
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	49.3	28.8	26.5	104.6
SOUTHWEST	912.1	535.5	800.2	2,247.7
SOUTHEXP	725.9	457.9	615.1	1,799.0
Total	6,342.6	4,817.7	5,101.5	16,261.8

Table 8-16 Active interfaces: January through March, 2013[30]

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
EKPC	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 8-3 PJM's footprint and its external interfaces



30 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Table 8-17 Active pricing points: January through March, 2013

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
LIND	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPT	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
OVEC	Active	Active	Active
Southeast	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active
Southwest	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power 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 the difference between actual and scheduled power flows at 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 by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[31]

For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. For the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh.[32] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[33]

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
CPLE	2,067	(159)	2,226
CPLW	(375)	-	(375)
DUK	229	446	(217)
EKPC	649	(368)	1,017
LGEE	365	856	(491)
MEC	(231)	(1,032)	801
MISO	(3,602)	1,303	(4,906)
ALTE	(1,589)	(723)	(866)
ALTW	(600)	(16)	(583)
AMIL	3,350	517	2,833
CIN	(1,557)	860	(2,417)
CWLP	(92)	0	(92)
IPL	(33)	26	(59)
MECS	(2,757)	944	(3,701)
NIPS	(1,727)	(57)	(1,669)
WEC	1,403	(246)	1,650
NYISO	(3,209)	(3,225)	15
LIND	(407)	(407)	0
NEPT	(756)	(756)	0
NYIS	(2,047)	(2,062)	15
OVEC	3,506	2,097	1,410
TVA	1,700	1,158	542
Total	1,098	1,076	22

Every external 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

31 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

32 The "Net Scheduled" values shown in Table 8-18 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 Table 8-1 through Table 8-6.

33 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

the specific interface price.[34] 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.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 8-19 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.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (3,985 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 2,946 GWh).

The IMO Interface Pricing Point with the IESO 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 mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
IMO	0	1,544	(1,544)
LINDENVFT	(407)	(407)	0
MISO	(2,953)	(2,397)	(556)
NEPTUNE	(756)	(756)	0
NORTHWEST	(231)	(11)	(220)
NYIS	(2,047)	(1,940)	(106)
OVEC	3,506	2,097	1,410
SOUTHIMP	3,985	3,790	196
CPLEIMP	0	0	0
DUKIMP	0	296	(296)
NCMPAIMP	0	119	(119)
SOUTHWEST	0	0	0
SOUTHIMP	3,985	3,374	612
SOUTHEXP	0	(844)	844
CPLEEXP	0	(112)	112
DUKEXP	0	(73)	73
NCMPAEXP	0	(0)	0
SOUTHWEST	0	(13)	13
SOUTHEXP	0	(645)	645
Total	1,098	1,076	22

34 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 8-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 8-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2013

	Actual	Net Scheduled	Difference (GWh)
LINDENVFT	(407)	(407)	0
MISO	(2,953)	(837)	(2,116)
NEPTUNE	(756)	(756)	0
NORTHWEST	(231)	(11)	(220)
NYIS	(2,047)	(1,956)	(90)
OVEC	3,506	2,097	1,410
SOUTHIMP	3,985	3,790	196
CPLEIMP	0	0	0
DUKIMP	0	296	(296)
NCMPAIMP	0	119	(119)
SOUTHWEST	0	0	0
SOUTHIMP	3,985	3,374	612
SOUTHEXP	0	(844)	844
CPLEEXP	0	(112)	112
DUKEXP	0	(73)	73
NCMPAEXP	0	(0)	0
SOUTHWEST	0	(13)	13
SOUTHEXP	0	(645)	645
Total	1,098	1,076	22

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, PJM should, recognizing that transactions sourcing in SPP and sinking in PJM will create flows across the southern border, require that market participants submit the transaction to enter the PJM footprint across a neighboring balancing authority that is mapped to the SouthIMP Interface price. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

Table 8-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 8-21 shows that for the first three months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (607 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO interface, and thus were assigned the MISO Interface Pricing point (261 GWh).

Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through March, 2013

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(1,589)	(723)	(866)	IPL		(33)	26	(59)
	MISO	(1,589)	(723)	(867)		IMO	0	232	(232)
	NORTHWEST	0	(1)	1		MISO	(33)	(244)	211
	SOUTHIMP	0	1	(1)		SOUTHIMP	0	39	(39)
ALTW		(600)	(16)	(583)	LGEE		365	856	(491)
	MISO	(600)	(16)	(583)		SOUTHEXP	0	(18)	18
AMIL		3,350	517	2,833		SOUTHIMP	365	874	(509)
	MISO	3,350	521	2,829	LIND		(407)	(407)	0
	SOUTHIMP	0	9	(9)		LINDENVFT	(407)	(407)	0
	SOUTHWEST	0	(13)	13	MEC		(231)	(1,032)	801
CIN		(1,557)	860	(2,417)		MISO	0	(1,379)	1,379
	IMO	0	607	(607)		NORTHWEST	(231)	2	(233)
	MISO	(1,557)	(261)	(1,296)		SOUTHIMP	0	345	(345)
	NORTHWEST	0	(11)	11	MECS		(2,757)	944	(3,701)
	NYIS	0	106	(106)		IMO	0	720	(720)
	SOUTHIMP	0	420	(420)		MISO	(2,757)	(65)	(2,692)
CPLE		2,067	(159)	2,226		SOUTHIMP	0	288	(288)
	CPLEEXP	0	(112)	112	NEPT		(756)	(756)	0
	SOUTHEXP	0	(8)	8		NEPTUNE	(756)	(756)	0
	SOUTHIMP	2,067	(39)	2,106	NIPS		(1,727)	(57)	(1,669)
CPLW		(375)	0	(375)		MISO	(1,727)	(58)	(1,669)
	SOUTHIMP	(375)	0	(375)	NYIS		(2,047)	(2,062)	15
CWLP		(92)	0	(92)		IMO	0	(16)	16
	MISO	(92)	0	(92)		NYIS	(2,047)	(2,046)	(1)
DUK		229	446	(217)	OVEC		3,506	2,097	1,410
	DUKEXP	0	(73)	73		OVEC	3,506	2,097	1,410
	DUKIMP	0	296	(296)	TVA		1,700	1,158	542
	NCMPAIMP	0	119	(119)		NORTHWEST	0	0	0
	SOUTHEXP	0	(53)	53		SOUTHEXP	0	(92)	92
	SOUTHIMP	229	157	72		SOUTHIMP	1,700	1,249	451
EKPC		649	(368)	1,017	WEC		1,403	(246)	1,650
	MISO	649	75	575		MISO	1,403	(246)	1,650
	SOUTHEXP	0	(474)	474	Total		1,098	1,076	22
	SOUTHIMP	0	31	(31)					

Table 8-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 8-22 shows that for the first three months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (720 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface (16 GWh).

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through March, 2013

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(112)	112	NORTHWEST		(231)	(11)	(220)
	CPLE	0	(112)	112		ALTE	0	(1)	1
DUKEXP		0	(73)	73		CIN	0	(11)	11
	DUK	0	(73)	73		MEC	(231)	2	(233)
DUKIMP		0	296	(296)	NYIS		(2,047)	(1,940)	(106)
	DUK	0	296	(296)		CIN	0	106	(106)
IMO		0	1,544	(1,544)		NYIS	(2,047)	(2,046)	(1)
	CIN	0	607	(607)	OVEC		3,506	2,097	1,410
	IPL	0	232	(232)		OVEC	3,506	2,097	1,410
	MECS	0	720	(720)	SOUTHEXP		0	(645)	645
	NYIS	0	(16)	16		CPLE	0	(8)	8
LINDENVFT		(407)	(407)	0		DUK	0	(53)	53
	LIND	(407)	(407)	0		EKPC	0	(474)	474
MISO		(2,953)	(2,397)	(556)		LGEE	0	(18)	18
	ALTE	(1,589)	(723)	(867)		TVA	0	(92)	92
	ALTW	(600)	(16)	(583)	SOUTHIMP		3,985	3,374	612
	AMIL	3,350	521	2,829		ALTE	0	1	(1)
	CIN	(1,557)	(261)	(1,296)		AMIL	0	9	(9)
	CWLP	(92)	0	(92)		CIN	0	420	(420)
	EKPC	649	75	575		CPLE	2,067	(39)	2,106
	IPL	(33)	(244)	211		CPLW	(375)	0	(375)
	MEC	0	(1,379)	1,379		DUK	229	157	72
	MECS	(2,757)	(65)	(2,692)		EKPC	0	31	(31)
	NIPS	(1,727)	(58)	(1,669)		IPL	0	39	(39)
	WEC	1,403	(246)	1,650		LGEE	365	874	(509)
NCMPAIMP		0	119	(119)		MEC	0	345	(345)
	DUK	0	119	(119)		MECS	0	288	(288)
NEPTUNE		(756)	(756)	0		TVA	1,700	1,249	451
	NEPT	(756)	(756)	0	SOUTHWEST		0	(13)	13
						AMIL	0	(13)	13
					Total		1,098	1,076	22

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange 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 these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

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 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 attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[35] 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.[36]

Real-Time and Day-Ahead PJM/MISO Interface Prices

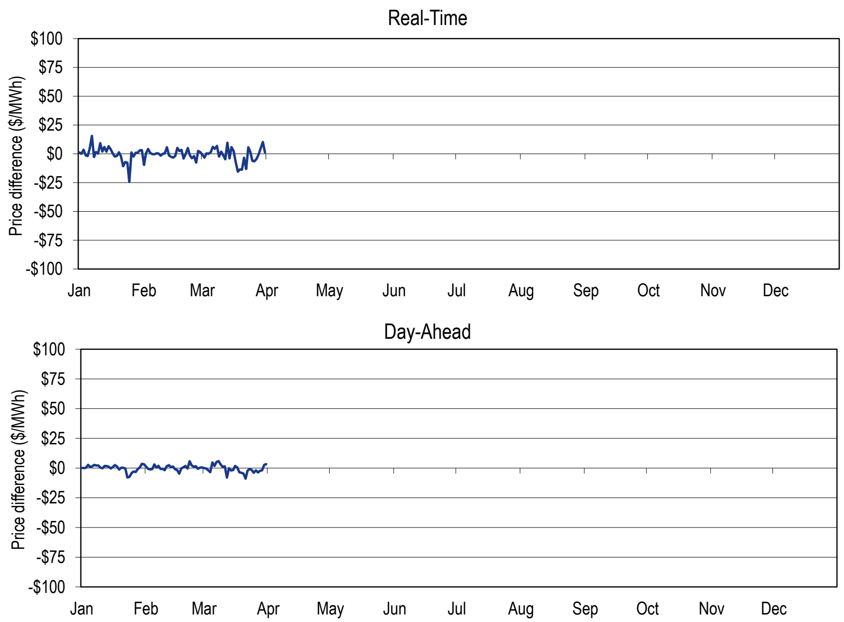
In the first three months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first three months of 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $29.73 while the MISO LMP at the border was $29.23, a difference of $0.50. While the average hourly LMP difference at the PJM/MISO border was only $0.50, the average of the absolute values of the hourly differences was $7.23. The average hourly flow during the first three months of 2013 was -1,667 MW. (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO price was lower than the average PJM price.) The direction of flow was consistent with price differentials in only 42.6 percent of hours in the first three months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $8.66. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $6.34. In the first three months of 2013, 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 $8.55. 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 $12.39. 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 $16.52. 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 $5.46.

In the first three months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $29.90 while the MISO LMP at the border was $29.72, a difference of $0.18.

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 (Figure 8-6).

35 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed May 6, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
36 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed January 16, 2013)

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first three months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 919 hours (42.6 percent of all hours), and was inconsistent with price differentials in 1,240 hours (57.4 percent of all hours). Table 8-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 919 hours where flows were uneconomic, 756 of those hours (82.3 percent) had a price difference greater than or equal to $1.00 and 427 of all uneconomic hours (46.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 1,240 hours where flows were economic, 1,060 of those hours (85.5 percent) had a price difference greater than or equal to $1.00 and 375 of all economic hours (30.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $313.55.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,240	100.0%	919	100.0%
$1.00	1,060	85.5%	756	82.3%
$5.00	375	30.2%	427	46.5%
$10.00	145	11.7%	236	25.7%
$15.00	78	6.3%	151	16.4%
$20.00	51	4.1%	95	10.3%
$25.00	31	2.5%	63	6.9%
$50.00	7	0.6%	22	2.4%
$75.00	4	0.3%	14	1.5%
$100.00	3	0.2%	9	1.0%
$200.00	1	0.1%	1	0.1%
$300.00	0	0.0%	1	0.1%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

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.[37]

37 See the 2012 *State of the Market Report fot PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

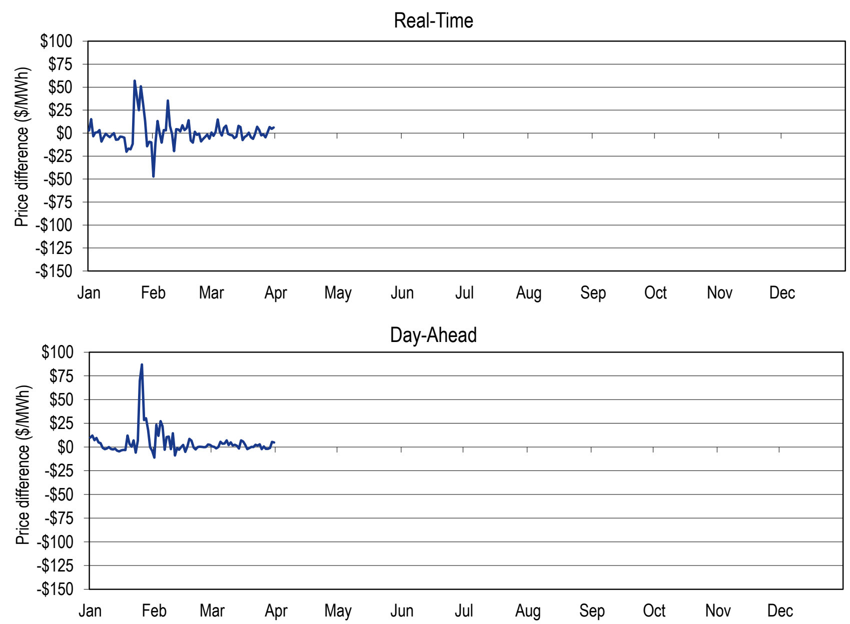
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first three months of 2013, 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 the NYISO. In the first three months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first three months of 2013, 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 the first three months of 2013, the PJM average hourly LMP at the PJM/NYISO border was $47.32 while the NYISO LMP at the border was $48.18, a difference of $0.87. While the average hourly LMP difference at the PJM/NYISO border was only $0.87, the average of the absolute value of the hourly difference was $18.08. The average hourly flow during the first three months of 2013 was -948 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.) The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first three months of 2013. In the first three months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $17.00. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $19.46. In the first three months of 2013, 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 $16.86. 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 $30.56. 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 $31.84. 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 $19.15.

In the first three months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $45.55 while the NYIS LMP at the border was $50.28, a difference of $4.73.

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 (Figure 8-6).

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March, 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first three months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,213 (56.2 percent of all hours), and was inconsistent with price differences in 946 hours (43.8 percent of all hours). Table 8-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 946 hours where flows were uneconomic, 870 of those hours (92.0 percent) had a price difference greater than or equal to $1.00 and 610 of all uneconomic hours (64.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $231.63. Of the 1,213 hours where flows were economic, 1,134 of those hours (93.5 percent) had a price difference greater than or equal to $1.00 and 780 of all economic hours (64.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $634.79.

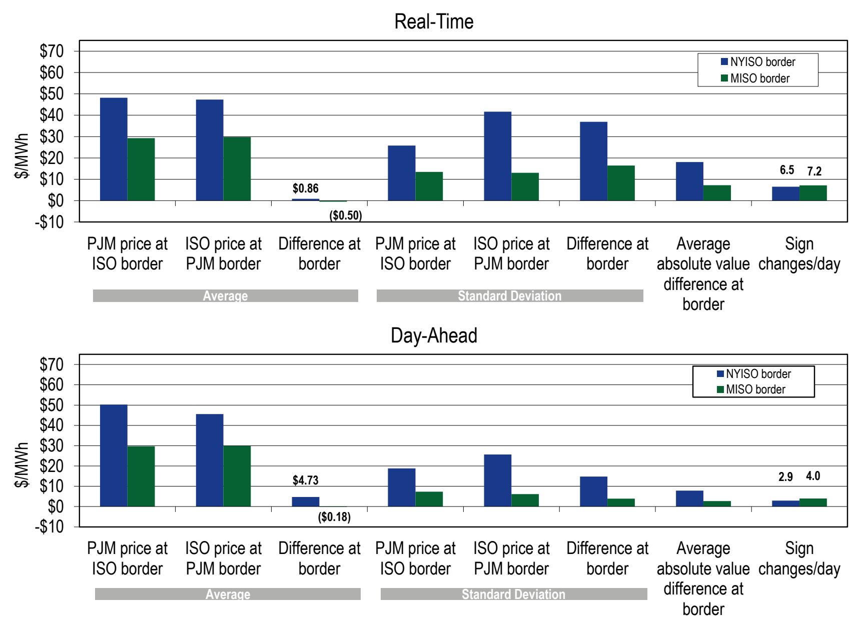
Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	946	100.0%	1,213	100.0%
$1.00	870	92.0%	1,134	93.5%
$5.00	610	64.5%	780	64.3%
$10.00	399	42.2%	468	38.6%
$15.00	308	32.6%	315	26.0%
$20.00	245	25.9%	243	20.0%
$25.00	205	21.7%	188	15.5%
$50.00	105	11.1%	92	7.6%
$75.00	54	5.7%	54	4.5%
$100.00	28	3.0%	42	3.5%
$200.00	2	0.2%	4	0.3%
$300.00	0	0.0%	2	0.2%
$400.00	0	0.0%	1	0.1%
$500.00	0	0.0%	1	0.1%

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.

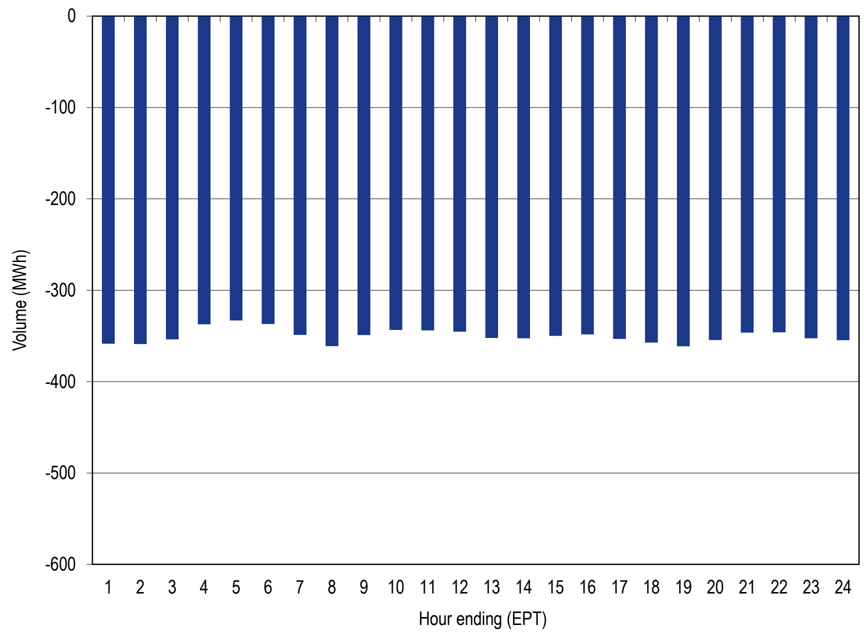
Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2013



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). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first three months of 2013, the PJM average hourly LMP at the Neptune Interface was $41.69 while the NYISO LMP at the Neptune Bus was $85.94, a difference of $44.25.[38] While the average hourly LMP difference at the PJM/Neptune border was $44.25, the average of the absolute value of the hourly difference was $54.16. The average hourly flow during the first three months of 2013 was -350 MW.[39] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 84.4 percent of the hours in the first three months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $58.12. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $32.43.

Figure 8-7 Neptune hourly average flow: January through March, 2013



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 (Linden, New Jersey) and NYISO (Staten Island, New York). In the first three months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first three months of 2013, the PJM average hourly LMP at the Linden Interface was $43.44 while the NYISO LMP at the Linden Bus was $64.00, a difference of $20.56.[40] While the average hourly LMP difference at the PJM/Linden border was $20.56, the average of the absolute value of the hourly difference was $30.13. The average hourly flow during the first three

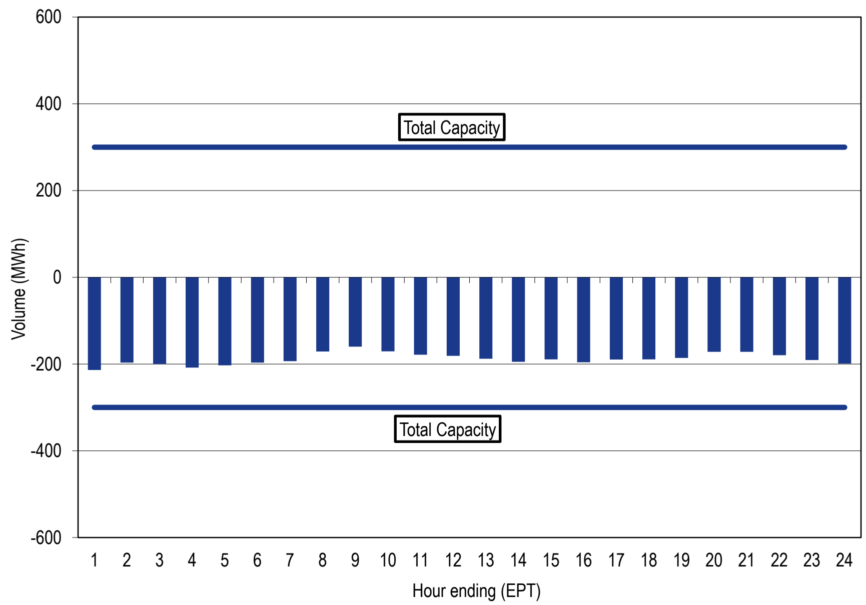
38 In the first three months of 2013, there were 92 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $44.34 while the NYISO LMP at the Neptune Bus during non-zero flows was $88.60, a difference of $44.26.

39 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -366 MW.

40 In the first three months of 2013, there were 144 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $63.15 while the NYISO LMP at the Neptune Bus during non-zero flows was $154.78, a difference of $91.63.

months of 2013 was -188 MW.[41] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 77.6 percent of the hours in the first three months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $32.51. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $21.71.

Figure 8-8 Linden hourly average flow: January through March, 2013[42]



Hudson Direct Current (DC) Merchant Transmission 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 by the end of the second quarter of 2013.

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.

PJM and MISO Joint Operating Agreement[43]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. 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. In 2012, MISO and

41 The average hourly flow during the first three months of 2013, ignoring hours with no flow, on the Linden VFT line was -202 MW.
42 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.
43 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 May 6, 2013)

PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[44]

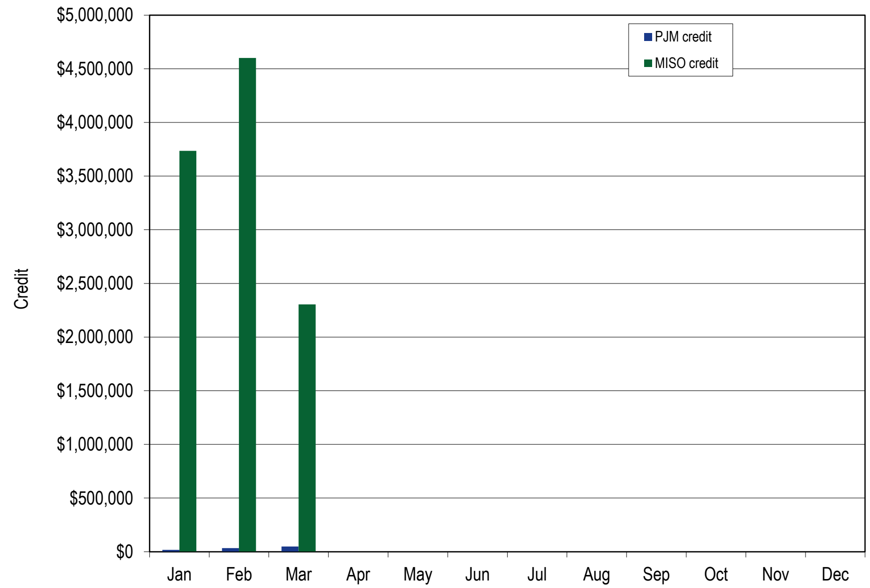
Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[45]

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 than 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 RCFs are subject to the market to market congestion management process.

In the first three months of 2013, MISO added 38 RCFs, compared to 7 RCFs added in the first three months of 2012 (35 RCFs were added by MISO in 2012). In the first three months of 2013, PJM added 10 RCFs, compared to 4 RCF's added in the first three months of 2012 (12 RCF's were added by PJM in 2012).

During the first three months of 2013, 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. Figure 8-9 shows credits for coordinated congestion management between PJM and MISO.

Figure 8-9 Credits for coordinated congestion management: January through March, 2013[46]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[47]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the

44 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.
45 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
47 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

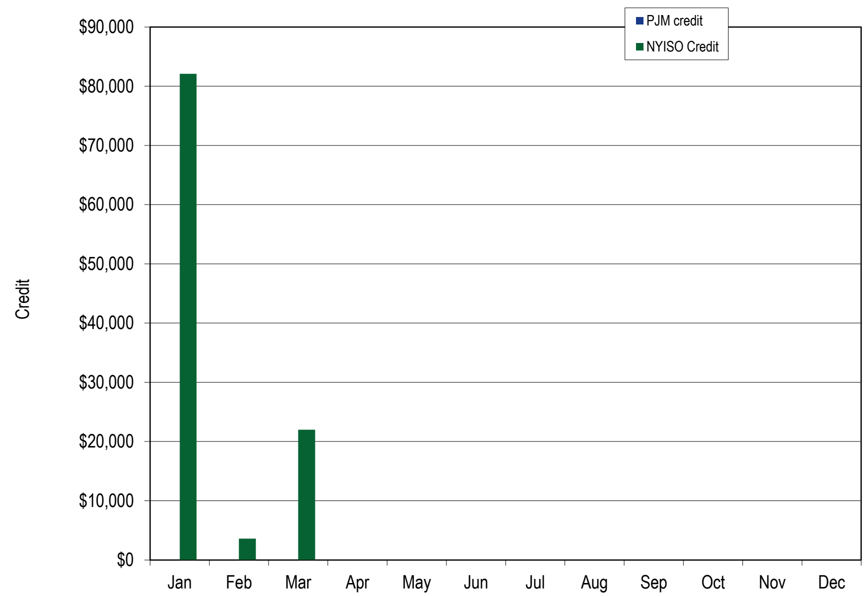
Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 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.

In the first three months of 2013, the market to market operations resulted in NYISO 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.

During the first three months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 8-10 shows credits for coordinated congestion management between PJM and NYISO.

Figure 8-10 Credits for coordinated congestion management (flowgates): January through March, 2013[48]



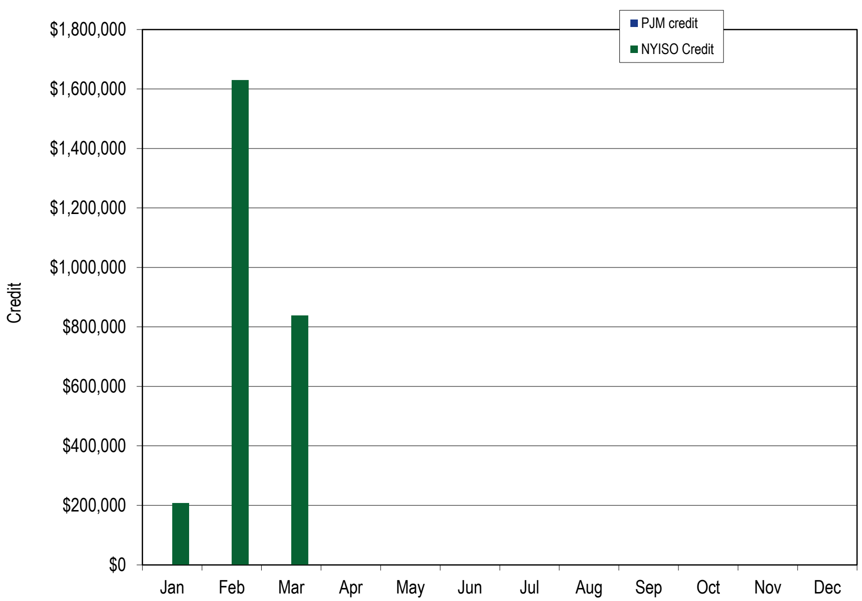
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM interface. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[49] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow

48 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

49 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (January 17, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed May 6, 2013)

is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first three months of 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 8-11 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 8-11 Credits for coordinated congestion management (PARs): January through March, 2013[50]



50 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

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 yearly basis, and, in the first three months of 2013, there were no developments. The agreement continued to be in effect in the first three months of 2013.

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.[51] On January 20, 2011, the Commission conditionally accepted the compliance filing.

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

51 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

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 the first three months of 2013, there were no developments. The agreement remained in effect in the first three months of 2013.

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.[52]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[53] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[54] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

Table 8-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.12	$34.06	$32.96	$32.96	$0.16	$1.11
PEC	$34.55	$35.35	$32.96	$32.96	$1.59	$2.39
NCMPA	$33.57	$33.73	$32.96	$32.96	$0.61	$0.78

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.46	$35.27	$33.08	$33.08	$1.39	$2.19
PEC	$35.46	$36.32	$33.08	$33.08	$2.38	$3.25
NCMPA	$34.88	$34.95	$33.08	$33.08	$1.80	$1.87

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

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 including lines controlled by PJM.[55] 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.[56]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[57] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special

52 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>. (Accessed May 6, 2013)
53 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).
54 See Docket Nos. ER12-1338-000 and ER12-1343-000.
55 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.
56 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
57 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.

protocol indefinitely.[58] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[59] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 8-27 below reflecting those charges effective May 1, 2012.

Table 8-27 Con Edison and PSE&G wheeling agreement data: January through March, 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$2,152,420	$32,582	$2,185,002	$0	$0	$0
Congestion Credit			$941,714			$0
Adjustments and Transmission Charges			($9,534,255)			$0
Net Charge			$10,777,544			$0

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (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 issued eight TLRs in the first three months of 2013, compared to six TLRs issued in the first three months of 2012. The fact that PJM has issued only eight TLRs in the first three months of 2013, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM TLRs increased by 33 percent, from six during the first three months of 2012 to eight during the first three months of 2013 (Table 8-28). In addition, the number of different flowgates for which PJM declared TLRs increased from four in the first three months of 2012 to six in the first three months of 2013. The total MWh of transaction curtailments increased by 528 percent, from 5,318 MWh in the first three months of 2012 to 28,062 MWh in the first three months of 2013.

MISO called more TLRs in the first three months of 2013 than in the first three months of 2012. MISO TLRs increased by 412 percent, from 26 in the first three months of 2012 to 107 in the first three months of 2013.

58 132 FERC ¶ 61,221 (2010).

59 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

Table 8-28 PJM and MISO TLR procedures: January, 2010 through March, 2013[60]

	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	6	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
Jan-12	1	9	1	6	4,920	6,274
Feb-12	4	6	2	6	0	5,177
Mar-12	1	11	1	6	398	31,891
Apr-12	0	14	0	7	0	8,408
May-12	2	17	1	10	3,539	30,759
Jun-12	0	24	0	7	0	31,502
Jul-12	11	19	5	4	34,197	46,512
Aug-12	8	13	1	6	61,151	13,403
Sep-12	2	5	1	4	21,134	12,494
Oct-12	3	9	2	6	0	12,317
Nov-12	4	10	2	6	444	24,351
Dec-12	1	22	1	12	0	17,761
Jan-13	4	42	3	17	13,453	103,463
Feb-13	4	26	3	10	14,609	66,086
Mar-13	0	39	0	13	0	53,122

60 The curtailment volume for PJM TLRs 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 TLRs 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>. (Accessed January 16, 2013)

Table 8-29 Number of TLRs by TLR level by reliability coordinator: January through March, 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	27	9	1	44	26	0	107
	NYIS	2	0	0	0	0	0	2
	ONT	0	0	0	0	0	0	0
	PJM	3	4	0	1	0	0	8
	SOCO	0	0	0	0	0	0	0
	SWPP	54	31	0	13	6	0	104
	TVA	9	10	0	0	2	0	21
	VACS	0	0	0	0	0	0	0
Total		95	54	1	58	34	0	242

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.[61]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013, compared to an average of 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012 (See Figure 8-12).

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 and unit commitment. 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. Additionally, the MMU is concerned about

61 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

the potential for market participants to utilize up-to congestion transactions to affect their other market positions, and the potential impacts that up-to congestion transactions may have on meeting FTR target allocations.

The MMU recommended 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 impacts on the actual operation of PJM markets. Alternatively, the MMU recommended 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.

While the MMU previously recommended the elimination of all internal PJM buses for use in up-to congestion bidding, on November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Figure 8-12 Monthly up-to congestion cleared bids in MWh: January, 2006 through March, 2013

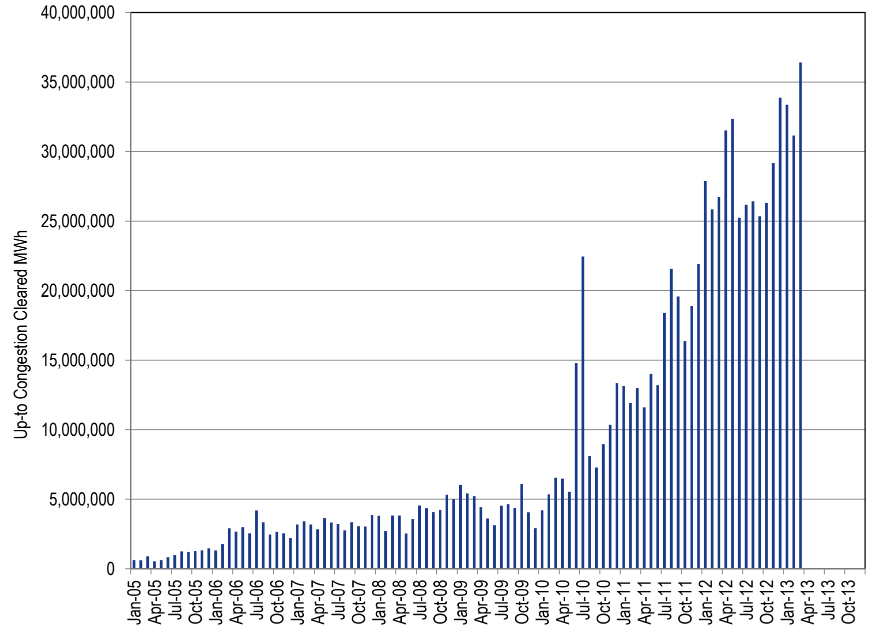


Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2013

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	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
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Total	899,888,259	856,940,667	37,584,717	368,875,677	2,163,289,320	19,915,132	17,637,142	762,500	10,271,924	48,586,698	341,506,153	329,435,313	18,219,264	110,097,470	799,258,199	8,383,807	7,376,733	335,992	3,431,413	19,527,945

In the first three months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 10.9 percent imports, 14.8 percent exports, 1.3 percent wheeling transactions and 73.0 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load. This can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

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. These modifications are currently being evaluated by PJM.

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 first three months of 2013 were $254, compared to -$15 in the first three months of 2012 (Table 8-31). 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 for the net uncollected congestion charges in the first three months of 2012. 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 the first three months of 2012, 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 planned for implementation in the second quarter of 2013.

Table 8-31 Monthly uncollected congestion charges: January, 2010 through March, 2013

Month	2010	2011	2012	2013
Jan	$148,764	$3,102	$0	$5
Feb	$542,575	$1,567	($15)	$249
Mar	$287,417	$0	$0	$0
Apr	$31,255	$4,767	($68)	
May	$41,025	$0	($27)	
Jun	$169,197	$1,354	$78	
Jul	$827,617	$1,115	$0	
Aug	$731,539	$37	$0	
Sep	$119,162	$0	$0	
Oct	$257,448	($31,443)	($6,870)	
Nov	$30,843	($795)	($4,678)	
Dec	$127,176	($659)	($209)	
Total	$3,314,018	($20,955)	($11,789)	$254

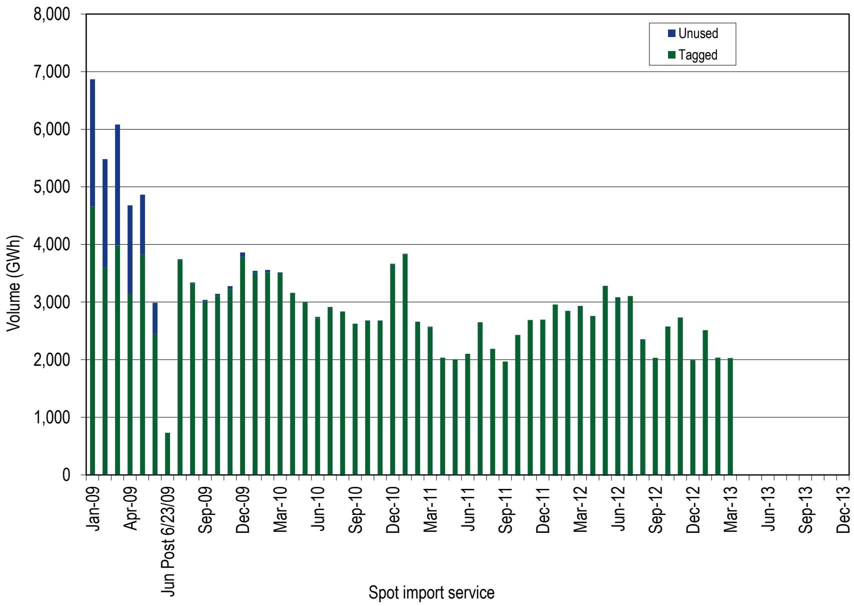
Spot Imports

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. Under this approach, market participants could 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. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[62] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding. The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

62 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>.

Figure 8-13 Spot import service utilization: January, 2009 through March, 2013



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 a valuable tool for market participants when implemented. 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, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted during the first three months of 2013.

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.[2]

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2013.

Table 9-1 The Regulation Market results were indeterminate for January through March, 2013

	January through March 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the three months of 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through March, 2013 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 indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance.
- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

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. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 6.3 percent of the hours in January through March, 2013.
- 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 competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

1 75 FERC ¶ 61,080 (1996).
2 For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

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 market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 12 percent of offers reflected economic withholding.
- 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 continues to be operated as a single market.

Market Structure

- **Supply.** In January through March 2013, 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 4.39. This is 33.4 percent increase over January through March 2012 when the ratio was 3.29, was the result of the decrease in demand.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through March, 2013, was 829 MW. This is a 124 MW decrease in the average hourly regulation demand of 953 MW in the same period of 2012.
- **Market Concentration.** In January through March 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1995 (1611 in January through March 2012), which is classified as "highly concentrated."[3] In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (67 percent of hours failed the three pivotal supplier test in January through March 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with costs parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[4] As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through March 2013 was $33.87. This is an increase of $21.26, or 168.6 percent, from the weighted average price for regulation in January through March 2012. The cost of regulation from January through March 2013 was $38.95. This is a $22.19 (132.4 percent) increase from the same time period in 2012.

3 See the *2012 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.

4 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007 their definition has changed. The RFC Synchronized Reserve Zone has now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[5]

Market Structure

- **Supply.** In January through March, 2013, 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.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, 2012, the requirement remained at 1,300 MW.
- **Market Concentration.** For January through March, 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4161 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through March, 2012, was 2638, which is classified as "highly concentrated."[6] In January through March, 2013, 35 percent of hours had a maximum market share greater than 40 percent, compared to 43 percent of hours in January through March, 2012.
- In the Mid-Atlantic Subzone, in January through March, 2013, 6.3 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through March, 2012, 49 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through March 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, 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.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $7.35 per MW in January through March, 2013, an increase of $1.29 per MW over January through March, 2012. The total cost of synchronized reserves per MW in January through March 2013 was $12.58, a $4.82 increase from the $7.76 cost of synchronized reserve in January through March 2012. The market clearing price was 58 percent of the total synchronized reserve cost per MW in January through March, 2013, down from 78 percent in January through March, 2012.
- **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 the first quarter of 2013.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[7] The purpose of this market is to

5 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 75.
6 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
7 See 117 FERC ¶ 61,331 (2006).

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.[8] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through March, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. 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 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with this direct marginal cost. As of March 31, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[9] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through March, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through March, 2013 was $0.01 per MW. In January through March, 2012, the weighted price of DASR was $0.01 per MW.

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 to automatically remain operating at reduced levels when disconnected from the grid.[10]

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 January through March, 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits of $38,980) to $10.66 per MW in the AEP zone (total credits of $22,352,763).

Ancillary services costs per MW of load: January through March 2002 - 2013

Table 9-4 shows PJM ancillary services costs for January through March, 2002, through 2013, 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.

8 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.
9 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 145.
10 OATT Schedule 1 § 1.3BB.

Table 9-4 History of ancillary services costs per MW of Load[11]: January through March 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.37	$0.59	$0.24	$0.00	$0.56	$1.76
2003	$0.65	$0.59	$0.22	$0.00	$0.98	$2.43
2004	$0.53	$0.63	$0.26	$0.17	$0.89	$2.48
2005	$0.46	$0.51	$0.25	$0.07	$0.57	$1.86
2006	$0.48	$0.46	$0.28	$0.09	$0.32	$1.62
2007	$0.58	$0.46	$0.30	$0.11	$0.50	$1.95
2008	$0.59	$0.47	$0.29	$0.07	$0.52	$1.94
2009	$0.37	$0.37	$0.34	$0.16	$0.56	$1.80
2010	$0.34	$0.38	$0.35	$0.05	$0.68	$1.80
2011	$0.27	$0.33	$0.39	$0.12	$0.84	$1.95
2012	$0.18	$0.41	$0.49	$0.03	$0.53	$1.64
2013	$0.28	$0.41	$0.63	$0.04	$0.94	$2.30

Conclusion

The design of the Regulation Market changed very significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first quarter of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

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 recommends that the rules for compliance be reevaluated.

The MMU concludes that the structure of the DASR Market was competitive in the first three months of 2013, 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.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three months of 2013. The MMU concludes that the DASR Market results were competitive in the first three months of 2013.

Regulation Market

The PJM Regulation Market continues to be operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012. On May 7, 2012, PJM switched to an improved optimizer called the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM made additional technical changes to the optimized solution and, to comply with FERC Order No. 755, implemented Performance Based Regulation.[12] On

11 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

12 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."

November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[13]

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as to keep the reportable metrics CPS1 and BAAL within acceptable limits.[14] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets to make use of and properly compensate a mix of fast and traditional response regulation resources.[15] A driver for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. FERC directed that the new and traditional resources be purchased in a single market, with compensation for both capacity (MW) and miles (total MW per minute measured in ΔMW/MW) provided. Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. On October 1, 2012, the PJM introduced a single market that included two distinct types of frequency response: RegA (traditional and slower oscillation signal) and RegD (faster oscillation signal). Within this new market design, resources can choose to follow RegA or RegD.[16]

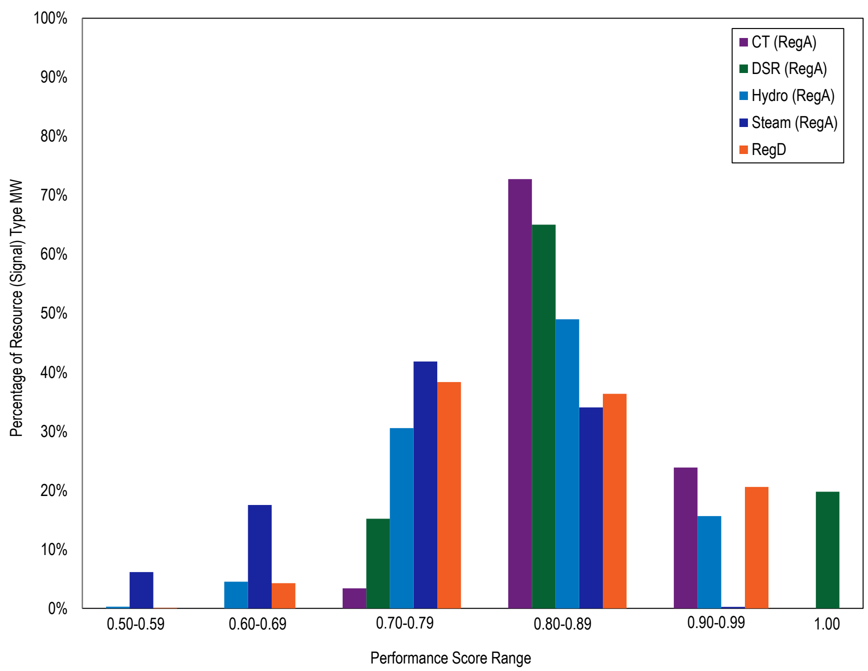
In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of units following the RegD signal depends on how much RegD following resources are used. Under PJM's August 15, 2012, proposal, the benefits factor can be as high as 2.9 but never lower than zero. Between January 1, 2013, and March 31, 2013, the lowest actual marginal benefit factor was 1.58. The highest marginal benefit factor was 2.899. The average marginal benefit factor was 2.655. Effective regulation is a function of two components, the benefits factor, which itself is a function of the amount of RegD regulation already committed; and the historical performance of the unit as measured by 100-hour average of performance scores. A unit's regulation capability MW multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.[17]

FERC's November 16, 2012 order only partially accepted the market design in PJM's August 15, 2012, filing. FERC's November 16, 2012, order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment. This created a dichotomy in the PJM regulation market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the first quarter of 2013.

Performance tracking is an essential element of the performance based Regulation Market. Every regulating unit for every hour has its performance tracked, measured, and recorded. An hourly performance score (0.0 to 1.0) is calculated and multiplied by the MW cleared when calculating payment. Additionally, hourly scores are stored and used as part of a 100 hour rolling average historical performance score to obtain an effective capability MW and performance MW used in clearing. Units are cleared and compensated for their effective MW. Regulation performance score measures the response of a regulating unit to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay - the time delay of the regulation response to a change in the regulation signal; correlation – the relationship between the regulating resource output and the regulation signal; and precision – the difference in energy provided from the difference in energy requested.[18] Figure 9-1 shows the average performance score by unit type and signal followed.

13 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)
14 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services, p.1
15 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").
16 For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."
17 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 59, (April 1, 2013); pps 61-62.
18 A full specification of each of the three criteria used in the performance score is presented in PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

Figure 9-1 Average performance score grouped by unit type and regulation signal type: January through March 2013



The use of a performance score to measure the accuracy of a regulating resource is the primary reason that the required regulation has been lowered from 1.0 percent to 0.7 percent of forecast peak load.

The performance based Regulation Market requires that unit owners provide two part offers for their regulation resources, an offer for regulation capability in terms of $/MW and a regulation performance offer in terms of $/MW. In addition, unit owners must enter the regulation signal type the unit will follow, RegA or RegD. Owners may enter price based offers subject to a combined offer cap of $100/MW.

Market Structure

Supply

Table 9-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in January through March 2013, to 8,149 MW from 9,257 MW during the same time period of 2012. Eligible regulation as a percentage of capability increased by nine percent over the same period in 2012.

Table 9-5 PJM regulation capability, daily offer[19] and hourly eligible: January through March 2012 and 2013[20]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2013 (Jan-Mar)	8,149	6,211	76%	3,551	44%
2012 (Jan-Mar)	9,257	6,878	74%	3,209	35%

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through March 2013	Settled MW, January through March 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
252	1,797,570	30	20,741	1.15%

The cost of each unit is calculated in market clearing using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score. As of October 1, 2012, a regulation resource's total offer is equal to the sum of its total capability ($/MW) and performance offer ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual within

19 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
20 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.

hour lost opportunity cost, of the most expensive cleared regulation resource in each interval. The total clearing price for the hour is the simple average of the twelve interval prices within the hour. The total clearing price of the hour (RMCP) is in two parts, the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the total clearing price for the hour and the performance clearing price for the hour.

Since the implementation of Regulation Performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012. Since the implementation of shortage pricing and changing the regulation requirement to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the price and cost of regulation have remained high. The weighted average regulation price for January through March, 2013 was $33.87. The regulation cost for January through March, 2013, was $38.95. The ratio of price to cost is significantly higher at 87 percent (compared with 76 percent in Q1 of 2012), meaning that more of the costs which used to come from LOC as a result of low load forecasts are now part of the price.

Since October 1, a number of resources have offered and cleared the regulation market following the RegD signal. As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.

In the period from January 1, 2013 through March 31, 2013, the marginal benefits factor (contribution to ACE correction) for cleared RegD following resources has ranged from 1.58 to 2.899 with an average over all hours of 2.66.

If the set of resources that follow the RegD signal were to be considered as a separate market, the HHI in that market from January through March 2013 was 5823.

Although the benefits factor for traditional (RegA following) resources is 1.0, the effective MW of RegA following resources is lower than the offered MW because the performance score is less than 1 (Figure 9-2). For January through March, 2013, the MW-weighted average RegA performance score was 0.79.

Figure 9-2 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; January through March 2013

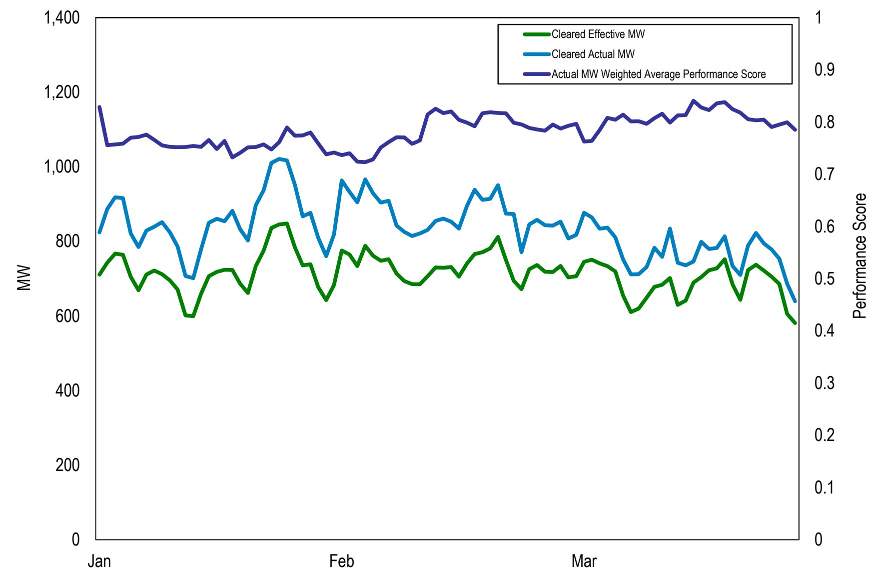
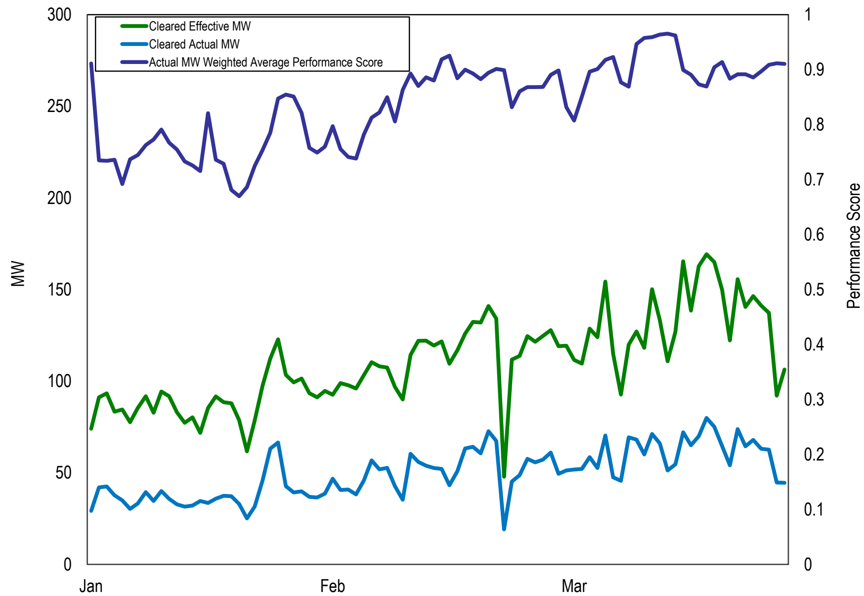


Figure 9-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; January through March 2013



For RegD resources, the effective MW are higher than the actual MW because their benefits factor at current participant levels is significantly greater than 1.0 (Figure 9-3). For January through March, 2013, the MW-weighted average RegD resource performance score was 0.86.

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. Prior to October 1, 2012, the regulation requirement was 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. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from one percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012. Then it was reduced to its current value of 0.70 percent of peak load forecast on December 18, 2012. Table 9-7 shows the required regulation and its relationship to the supply of regulation.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86

PJM's performance as measured by CPS and BAAL standards has not been reduced as a result of the lower regulation requirement.[21]

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for January through March of 2012 and 2013. The average HHI of 1995 is classified as moderately concentrated and is higher than the HHI for the same period in 2012.

Table 9-8 PJM cleared regulation HHI: January through March 2012 and 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Mar)	757	1995	5449
2012 (Jan-Mar)	814	1611	4429

21 *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 9-4 compares the 2013 HHI distribution curves with distribution curves for the same periods of 2012 and 2011.

Figure 9-4 PJM Regulation Market HHI distribution: January through March 2011, 2012, and 2013

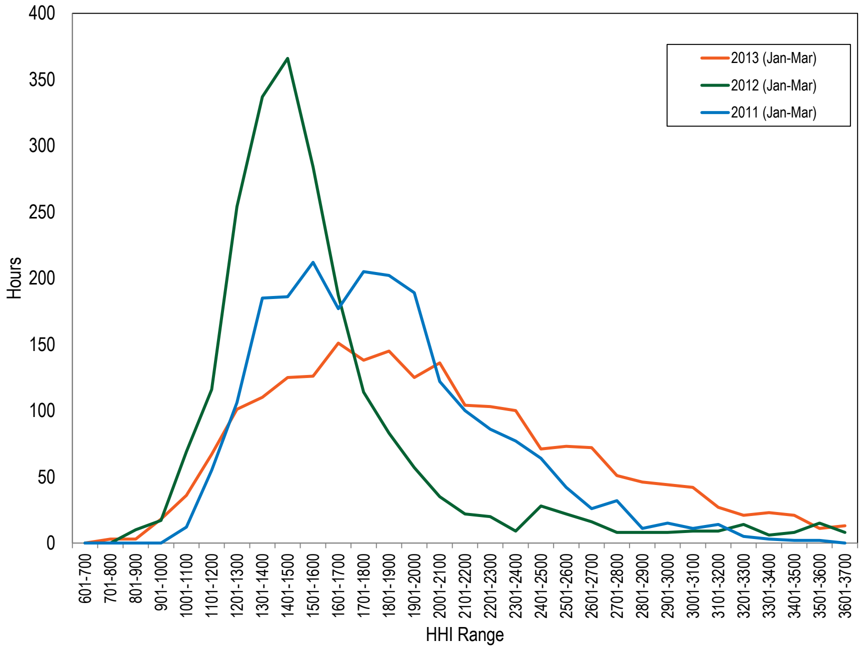


Table 9-9 includes a monthly summary of three pivotal supplier results. In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[22] In March, 2013, 97 percent of hours had one or more pivotal supplier and in 78 percent of hours all suppliers were pivotal. Offer capping in the regulation market has little impact on prices because offers are a smaller component of price than is LOC (Figure 9-6).

The MMU concludes from these results that the PJM Regulation Market in January through March 2013 was characterized by structural market power in 88 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through March 2011, 2012 and 2013

	2013	2012	2011
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	83%	71%	95%
Feb	82%	67%	93%
Mar	97%	64%	94%

Market Conduct

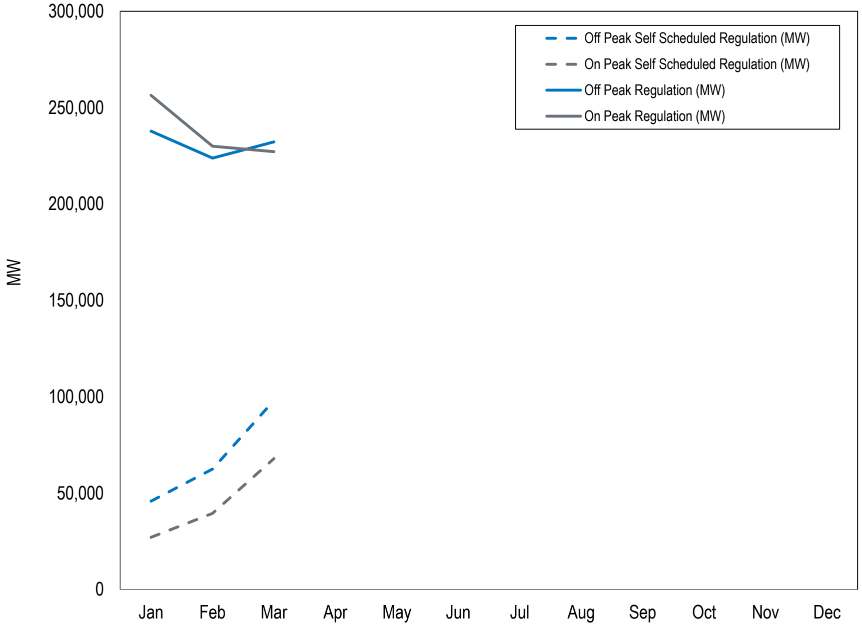
Offers

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 providers bilaterally, or self-schedule regulation to satisfy their obligation (Table 9-10).[23]

22 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.

23 See PJM "Manual 28: Operating Agreement Accounting," Revision 59, (April 22, 2013); para 4.1, pp 14.

Figure 9-5 Off peak and on peak regulation levels: January through March 2013



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation Q1 of 2013, 73 percent was purchased in the spot market, 24.0 percent was self scheduled, and 2.8 percent was purchased bilaterally (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
2013	Jan	413,304	72,880	8,070	494,253
2013	Feb	338,990	102,005	12,808	453,803
2013	Mar	275,880	165,987	17,554	459,421
2012	Jan	553,686	164,806	21,261	739,753
2012	Feb	481,004	175,757	20,456	677,217
2012	Mar	477,564	144,408	19,683	641,655

Demand resources offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing demand resources to offer 0.1 MW facilitated participation by demand resources. Although their impact remains small the participation of demand resources in regulation is growing. For January through March, 2013, approximately fifty percent of hours cleared some DSR regulation.

The Minimum Regulation MW parameter was reintroduced in 2012. This parameter allows regulation owners to specify a minimum amount of regulation that can be cleared, which imposes a constraint on the ASO's three product optimization. For the marginal unit, the ASO may need to clear less than an individual unit's offered amount of regulation in order to meet the regulation requirement. As a result of this parameter, there are a significant number of hours in which the ASO will have to clear more MW than is optimal or skip the marginal unit and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

Market Performance

Price

The weighted average RMCP for January through March, 2013, was $33.87. This is a 166.6 percent increase from the January through March 2012 weighted average RMCP of $12.64. Figure 9-6 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through March 2013

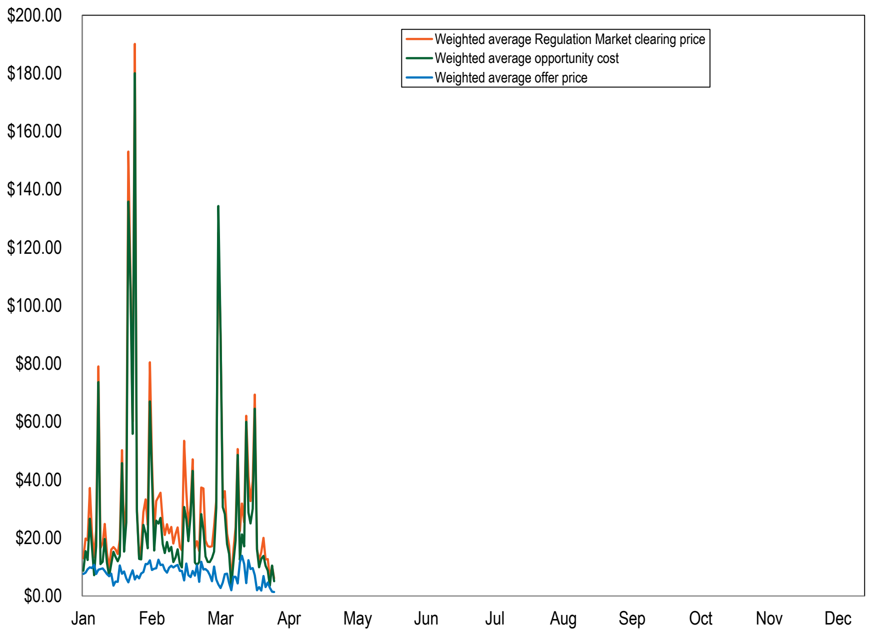


Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

There were several hourly price spikes in the ancillary services markets during the second half of January (Figure 9-7). The spikes were driven entirely by LOC costs resulting from high LMPs. The spikes were most acute in the capability regulation market. The LOC component of capability regulation is the most volatile component of regulation prices. The RMCP reached $228.87 and $448.26 in hours 11 and 12 of January 22, 2013. Prices reached $479.22 and $571.19 in hours 14 and 15 of January 25, 2013. In all there were 39 hours in January where the RMCP was over $100.

Figure 9-7 Ancillary Services Price spikes; January 20-January 29, 2013

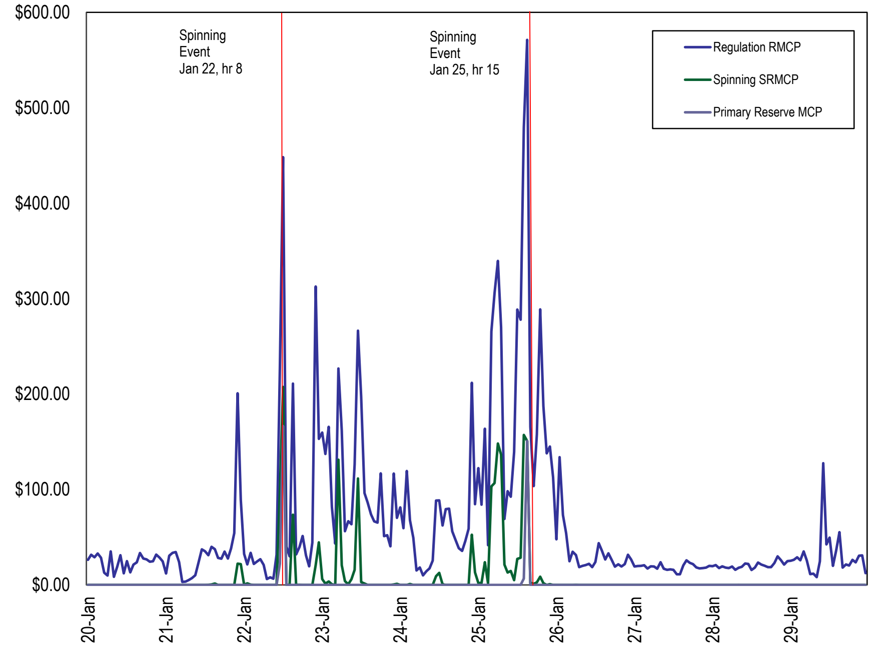


Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through March 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

Table 9-12 Total regulation charges: January through March 2013 and 2012

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($/MW)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2012	Jan	739,753	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	$12.61	$17.31	73%

A breakdown of the cost of regulation into its capability, performance, and opportunity cost components is shown in Table 9-13.

Table 9-13 Components of regulation cost: January through March 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30

Table 9-14 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through March 2013 than it was in January through March 2012. This is an improvement which resulted from the use of pricing based on real-time LMP instead of forecast LMP as had been done prior to shortage pricing in October 1, 2012.

Table 9-14 Comparison of average price and cost for PJM Regulation, January through March 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.05	$30.67	59%
2011	$11.51	$24.83	46%
2012	$12.61	$16.76	75%
2013	$33.87	$38.95	87%

Primary Reserve

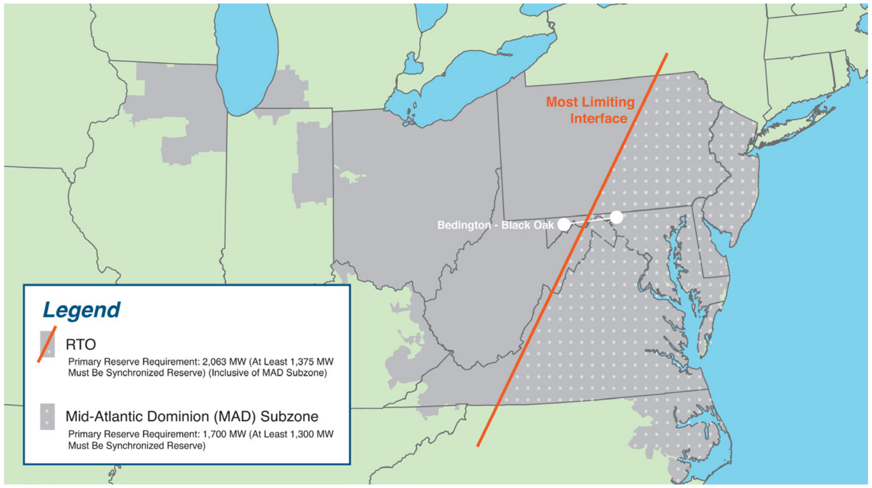
Reserves are provided by generating capability that is standing by ready for service if an unforeseen event causes a need for it. The need can be short-term and critical in the event of a disturbance or generator outage or longer term. NERC defines such losses and defines reporting requirements in "NERC Performance Standard BAL-002-0, Disturbance Control Performance." PJM defines its obligation in M-12.[24] NERC calls short-term reserve contingency reserve and specifies it as energy available in 15 minutes. PJM satisfies this requirement and calls it Primary Reserve. PJM specifies it as energy available within 10 minutes. Units in a shutdown state may satisfy the primary reserve requirement if they can start within 10 minutes. PJM retains a synchronized reserve requirement.

Requirements

PJM must satisfy the contingency reserve requirements specifications of the Reliability*First* Corporation and VACAR. For the RTO reserve zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Of that 2,063 MW, PJM requires that at least 1,375 MW be on line and synchronized to the grid (Figure 9-8).

24 See PJM. "Manual 12: Balancing Operations" Revision 27, Attachment D, "Disturbance Control Performance/Standard" (December 20, 2012), p. 84.

Figure 9-8 PJM RTO geography and primary reserve requirement: January through March 2013



Because of constrained deliverability within the RTO, PJM imposes a further restriction by creating a sub-zone within the RTO called the Mid-Atlantic Dominion sub-zone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. The Mid-Atlantic Dominion sub-zone is defined approximately by the geography in Figure 9-8. It is defined exactly by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the most limiting constraint, currently Bedington-Black Oak.[25]

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Sub-zone. The two requirements of the Mid-Atlantic Dominion Reserve Zone, primary reserve (1,700 MW) and synchronized reserve (1,300 MW) are satisfied by a set of energy products optimized to minimize total cost (Figure 9-9). The components of the Mid-Atlantic Dominion Primary Reserve Zone are Tier 1 synchronized reserve which is priced at $0 unless there is a shortage event or a spinning event, Tier 2 synchronized reserve which is satisfied by the Synchronized Reserve Market and priced economically, Demand Response (DSR) which is priced at the Synchronized Reserve Market clearing price, non-synchronized reserve (limited to no more than 50 percent of the primary reserve requirement) which is priced only when it must be dispatched at an optimized clearing price by the ASO, and synchronized reserve available in the Mid-Atlantic Dominion Reserve Zone from the RTO Reserve Zone across the most limiting constraint (usually Bedington-Black Oak).

Figure 9-9 Components of Mid-Atlantic Dominion Subzone Primary Reserve (Daily Averages): January through March, 2013

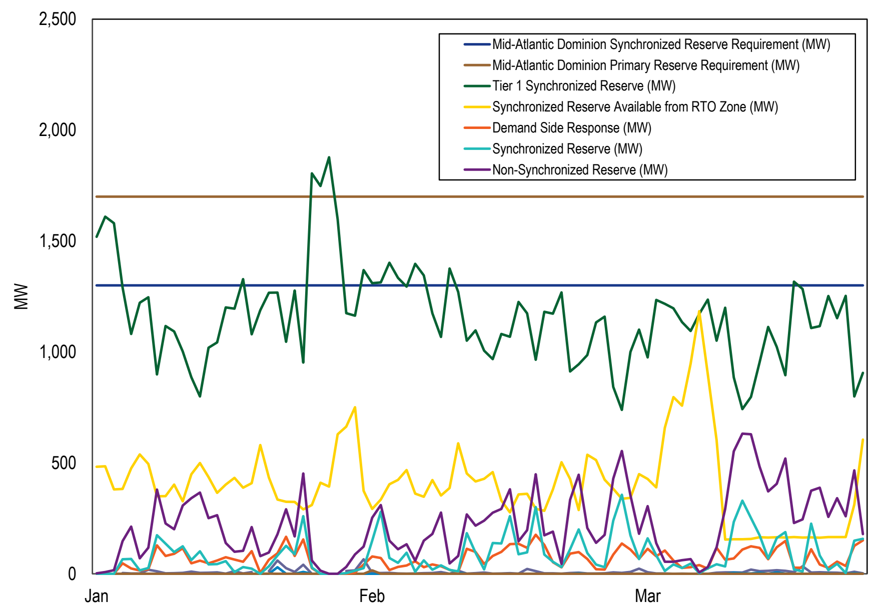


Figure 9-9 shows that Tier 1 Synchronized Reserve remains the major contributor to satisfying the reserve requirements. Synchronized reserve available inside the sub-zone from the RTO Zone is also a major contributor.

25 The specific constrained interface may be revised by PJM to meet system reliability needs. Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 75.

Both of these components have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve clears a separate market less frequently because (like DASR) it is available without redispatch from CTs and some hydro units. Tier 2 synchronized reserve is dispatched at a market clearing price.

In 43 hours between January 1 and March 31, 2013 the Non-Synchronized Reserve Market cleared at greater than $0.00. Non-synchronized reserve only clears when synchronized reserve also clears.

Shortage Pricing

On October 1, 2012 PJM introduced shortage pricing which made major changes to the structure and operation of the PJM reserve markets. PJM now has two markets to satisfy the primary reserve requirement; the Synchronized Reserve Market (Tier 2), and the new Non-Synchronized Reserve Market. The Synchronized Reserve Market dispatches Tier 2 synchronized reserve plus demand response to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units on-line synchronized to the grid. Units offering synchronized reserve which clear the Synchronized Reserve Market are Tier 2 units. The primary reserve requirement is then satisfied by Tier 1 plus Tier 2 plus Non-synchronized reserve.

If IT SCED and RT SCED forecast a primary reserve or synchronized reserve shortage, then PJM will implement shortage pricing through the inclusion of primary reserve or synchronized reserve penalty factors.[26]

From January through March, 2013 no location experienced a reserve shortage.

Synchronized Reserve Market

Prior to October 1, 2012, PJM operated two synchronized reserve markets because of differing synchronized reserve requirements specified by two different reliability regional authorities, Reliability*First* Corporation and VACAR. Those two synchronized reserve zones (Southern and RFC) are now merged into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications.[27]

Market Structure

Supply

For the first three months of 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DSR to 25 percent of the synchronized reserve requirement since it was introduced into the market in August 2006. On December 6, 2012, PJM increased this amount to 33 percent of the synchronized reserve requirement.

Total MW of cleared demand side resources decreased in January through March of 2013 over 2012 (from 172,745 MW to 129,646 MW). The DSR share of the total Synchronized Reserve Market increased from 38 percent in January through March of 2012 to 48.0 percent in the same time period of 2013. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 8.5 percent of hours in January through March of 2013 compared to 14 percent of hours in during the same time period of 2012. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone has made more Tier 1 reserve available to the subzone. The former Dominion Zone had an excess of Tier 1 lessening the number of hours when the subzone has to clear a Tier 2 market. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.3 for the Mid-Atlantic Dominion Subzone.[28] This is a 20.4 percent increase from January through March 2012 when the ratio was 1.08. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. It is important to note however that the Mid-Atlantic Dominion Subzone is bigger than the Mid-Atlantic Subzone which was the basis for the Q1 2012 metric. For the RTO Zone the offered and

26 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Reserve Markets.

27 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Synchronized Reserve Markets.

28 The Synchronized Reserve Market in the Southern Region between January and September, 2012 cleared in so few hours that related data for that market are not meaningful.

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.

Demand

With Shortage Pricing on October 1, 2012, PJM made a geographic change to the Synchronized Reserve Market footprint. The previous Southern Zone (Dominion) was merged into the previous Mid-Atlantic Sub-zone to become the Mid-Atlantic Dominion Sub-zone. The Synchronized Reserve requirement remains 1,300 MW but the primary reserve requirement (a combination of 10-minute synchronized reserve and 10-minute non-synchronized reserve) is set to 1,700 MW.

Because there is a large amount of Tier 1 available in the non-Mid-Atlantic Dominion regions of the RTO, a Synchronized Reserve Market usually does not have to be cleared in the RTO Synchronized Reserve zone. In January through March, 2013, in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in less than one percent of hours. From January through March 2013 in the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 38 percent of hours at an average of 306 MW. Note that there is more Tier 1 MW available in the Mid-Atlantic Dominion Subzone during the first quarter of 2013 than there was in the Mid-Atlantic Subzone in 2012, not only because of its integration with Dominion, but also because the transfer capability for Tier 1 from the RTO Zone into the Mid-Atlantic Subzone is now set to 100 percent.

As of March 31, 2013, the synchronized reserve requirement for the RTO synchronized reserve zone is 1,375 MW. The Mid-Atlantic Dominion synchronized reserve zone requirement is 1,300 MW.

Table 9-15 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through March 2013

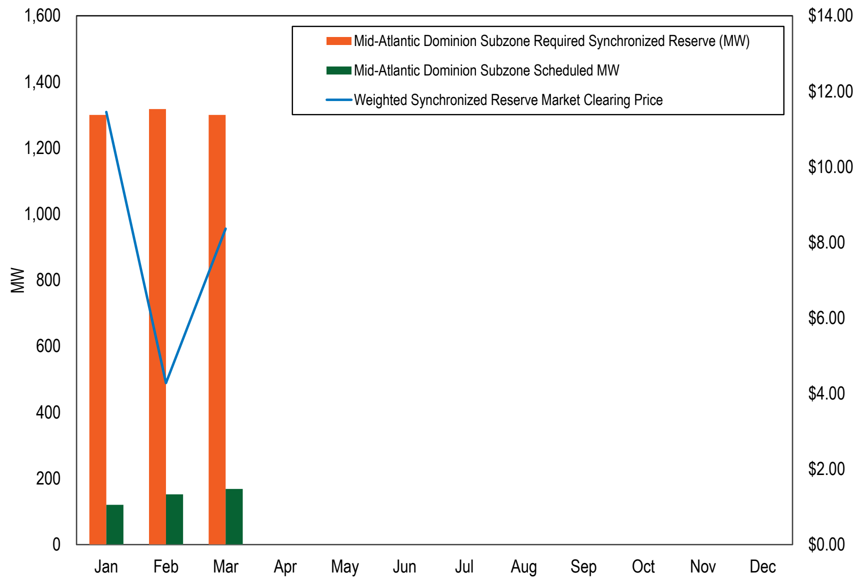
Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010		1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently Bedington-Black Oak) from the synchronized reserve zone's requirement each 5-minute period. Market demand is further reduced by subtracting the amount of self-scheduled Tier 2 resources.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement for both the RTO Zone and the Mid-Atlantic Dominion Subzone was raised to 1,780 MW for eight hours on February 2, 2013.

Figure 9-10 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through March of 2013, for the Mid-Atlantic Dominion Synchronized Reserve Market.

Figure 9-10 Mid-Atlantic Dominion Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March 2013



The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In January through March 2013, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 8 hours with an average SRMCP of $0.64. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market in 38 percent of all hours during January through March of 2013 at a weighted SRMCP of $8.03.

For the Mid-Atlantic Dominion Subzone from January through March 2013 the requirement is 1,300 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. The former Southern Synchronized Reserve Zone (integrated into the Mid-Atlantic Dominion Synchronized Reserve Zone on October 1, 2012) 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.[29] The amount of 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The VACAR requirement for the former Southern Synchronized Reserve Zone is now satisfied by the Synchronized Reserve requirement for the Mid-Atlantic Dominion Synchronized Reserve Subzone.

Market Concentration

The HHI from January through March 2012 for the Mid-Atlantic Subzone was 2638, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from January through March 2013 was 4161, which is defined as highly concentrated. Note that the HHI for 2013 includes both inflexible and flexible assigned MW. The largest hourly market share was 100 percent and 35 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 43 percent of all hours Q1 2012). Most synchronized reserve is provided by inflexible scheduled Tier 2 resources.[30] When there is not enough Tier 2 or when the IT SCED or RT SCED sees a need, flexible reserve units are assigned spinning. Flexible synchronized reserve is a much smaller market. Looking at the flexible unit sector of the synchronized reserve market from January through March, 2013, the hourly average HHI (all hours in which a market was cleared and flexible units were part of the market) was 8936.

The MMU estimates that in January through March, 2013, 6.3 percent of hours in the Mid-Atlantic Dominion Subzone would have failed a three pivotal supplier test (Table 9-12). This is significantly lower than the 49 percent that the MMU calculates would have failed the three pivotal supplier test in January through March, 2012. The reason for the decline is the increasing significance

29 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 54 (October 1, 2012), p. 71.

30 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT SCED runs.

of demand response in the supply of synchronized reserve. Demand response MW were 49 percent of the settled synchronized reserve tier 2 MW in January through March, 2013. These results indicate that the Mid-Atlantic Dominion Sub-zone, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Table 9-16 Mid-Atlantic Dominion Sub-zone[31] Synchronized Reserve Market monthly three pivotal supplier results: 2010, 2011, 2012, and 2013

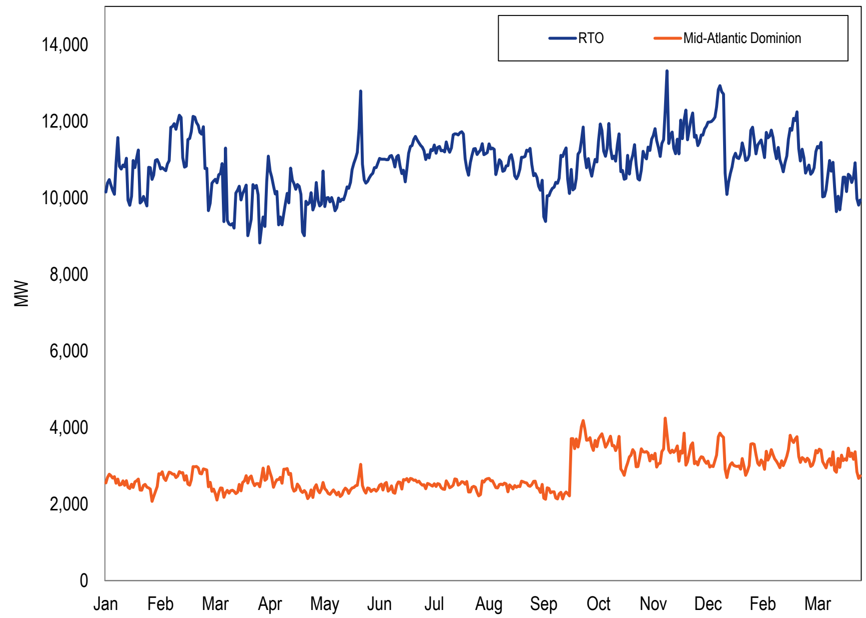
Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	1%	45%	92%	64%
Feb	11%	40%	99%	49%
Mar	7%	38%	74%	65%
Apr		33%	83%	31%
May		15%	46%	45%
Jun		29%	14%	10%
Jul		10%	19%	23%
Aug		3%	25%	18%
Sep		4%	56%	17%
Oct		9%	73%	54%
Nov		17%	84%	83%
Dec		25%	88%	40%

Market Conduct

Offers

Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, 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. Figure 9-11 shows the daily average of hourly offered Tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Sub-zone. Note that the geography of the RTO zone and the Mid-Atlantic subzone changed on October 1 with shortage pricing.

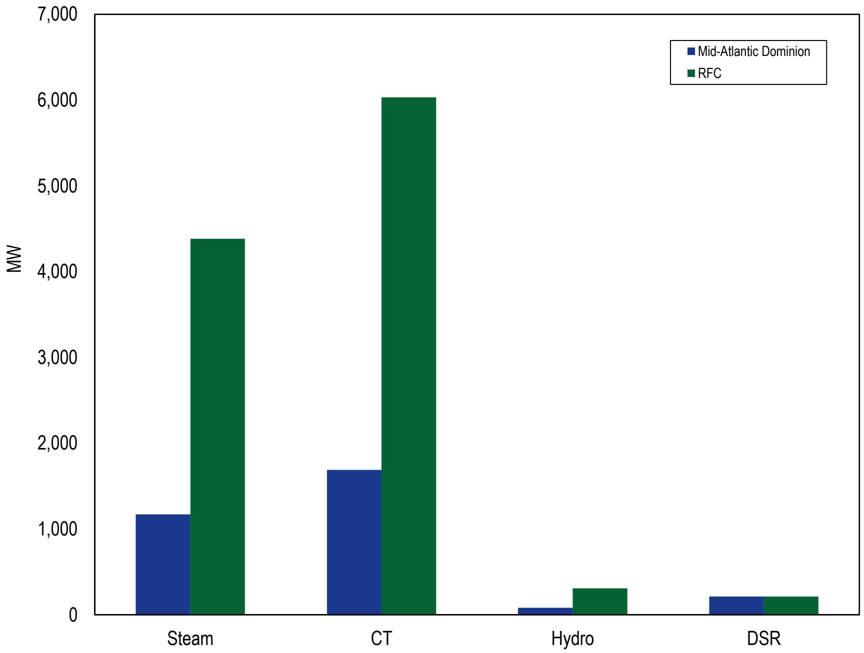
Figure 9-11 Tier 2 synchronized reserve average hourly offer volume (MW): January 2012 through March 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-12 shows average offer MW volume by market and unit type.

31 Note that the market expanded in October 2012 with the addition of Dominion.

Figure 9-12 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March 2013



DSR

Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DSR is always an inflexible resource. In January through March 2013, DSR was 49 percent of all cleared Tier 2 synchronized reserves, compared to 38 percent for the same period in 2012. In 16 percent of the hours in which synchronized reserve was cleared, all cleared MW were DSR (Table 9-17). In the hours when all cleared MW were DSR, the simple average SRMCP was $0.11. The simple average SRMCP for all cleared hours was $6.97.

Table 9-17 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: October through December 2012, and January through March 2013

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%
2013	Jan	$10.05	$0.06	7%
2013	Feb	$3.16	$0.06	5%
2013	Mar	$8.57	$0.16	12%

Market Performance

Price

Figure 9-13 shows the weighted average Tier 2 price and the cost per MW associated with meeting synchronized reserve demand in the Mid-Atlantic Dominion Sub-zone. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market Clearing Price (SRMCP).

Table 9-18 shows the monthly weighted average SRMCP, all credits including LOC credits, MW scheduled by PJM, and MW added by either the IT SCED or RT SCED for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in January through March 2013 was $7.35 while the corresponding cost of synchronized reserve was $12.58. The price for synchronized reserve in January through March 2012 was $6.06 while the cost was $7.76. Although the price of synchronized reserve rose slightly from Q1 of 2012, the cost rose significantly.

Table 9-18 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: January through March 2013

Year	Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	PJM Tier 2 and DSR Scheduled Synchronized Reserve MW	Flexible Synchronized Reserve Added by SCED (MW)	Self Scheduled MW
2013	Jan	$12.48	$1,224,123	68,540	15,270	102
2013	Feb	$3.70	$1,140,543	102,141	41,251	598
2013	Mar	$8.02	$2,250,953	124,863	14,727	0

The RTO Reserve Zone requirement was satisfied by Tier 1 in all but eight hours of January through March 2013. On October 1, 2012, the RFC Synchronized Reserve Zone became the RTO Reserve Zone. The Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in all but 58 hours from January through March 2013. In the 58 hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $128.70 and the weighted average clearing price was $1.41.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through March 2013, the price of Tier 2 synchronized reserves was 58 percent of the cost. In January through March 2012, the price to cost ratio was 70 percent.

Figure 9-13 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through March 2013

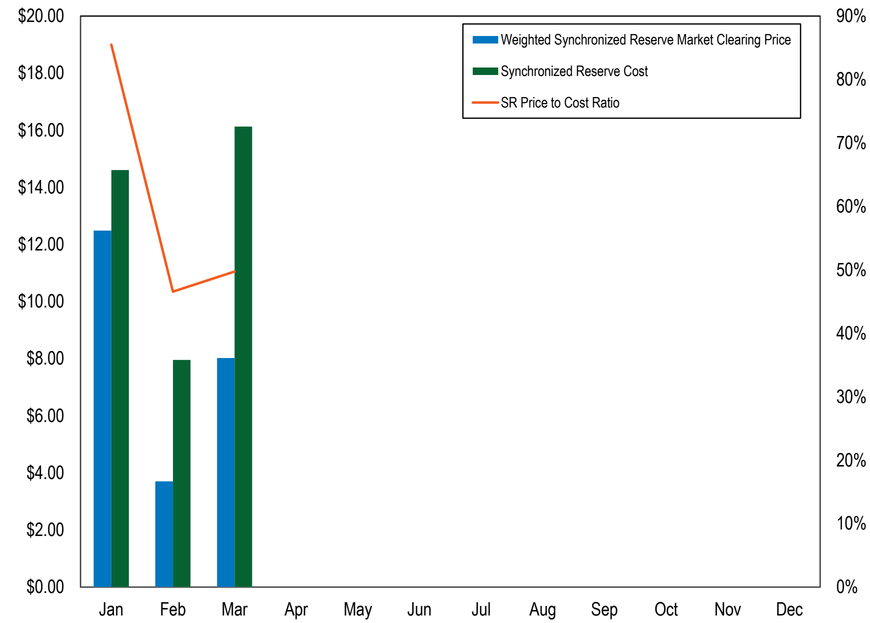


Table 9-19 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-19 Comparison of yearly weighted average price and cost for PJM Synchronized Reserve, January through March 2005 through 2013

Year	Weighted Synchronized Reserve Market Price	Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Mar)	$13.29	$17.59	76%
2006 (Jan-Mar)	$14.57	$21.65	67%
2007 (Jan-Mar)	$11.22	$16.26	69%
2008 (Jan-Mar)	$10.65	$16.43	65%
2009 (Jan-Mar)	$7.75	$9.77	79%
2010 (Jan-Mar)	$10.55	$14.41	73%
2011 (Jan-Mar)	$10.96	$13.22	83%
2012 (Jan-Mar)	$6.06	$7.76	78%
2013 (Jan-Mar)	$8.07	$12.90	63%

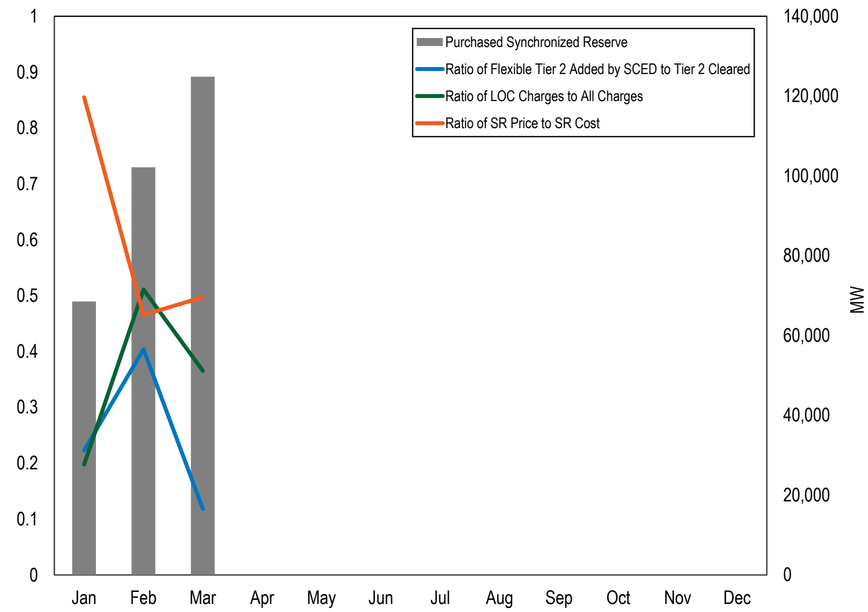
Before shortage pricing the reason for relatively low actual price to cost ratio was the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio was in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers needed the reserves for reliability reasons (Table 9-18). The problem of lower forecast LMPs than real-time LMPs was solved by the use of real-time pricing.

Beginning with Shortage Pricing on October 1, 2012, PJM expanded its use of Tier 1 biasing (a technical term). Negative Tier 1 biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines use to determine how much Tier 2 MW to schedule. A negative bias reduces the amount of Tier 1 estimated and therefore increases the amount of inflexible Tier 2 which must be purchased. A negative bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. This reduces the likelihood that the IT SCED and/or RT SCED will add flexible Tier 2 MW during the market hour.

PJM can bias the Tier 1 synchronized reserve estimate that the ASO uses when it determines the amount of synchronized reserve to buy. The bias forces the ASO to clear more (or less) inflexible Tier 2 synchronized reserve than it would otherwise procure. Most of the bias adjustments reduce the amount of Tier 1 estimated thereby increasing the amount of inflexible Tier 2 procured. The increased inflexible Tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real-time. This leads to a significant amount of Tier 2 synchronized reserves being paid when they are not needed or when the price is zero. A price of $0 means that the Tier 2 synchronized reserve requirement was determined to be zero because there was enough Tier 1.

From January through March, 2013, a total of 48,867 MWH of Tier 2 synchronized reserve was purchased for hours when the price was later calculated to be $0. The charges (to compensate for lost opportunity costs) for this synchronized reserve were $294,064.

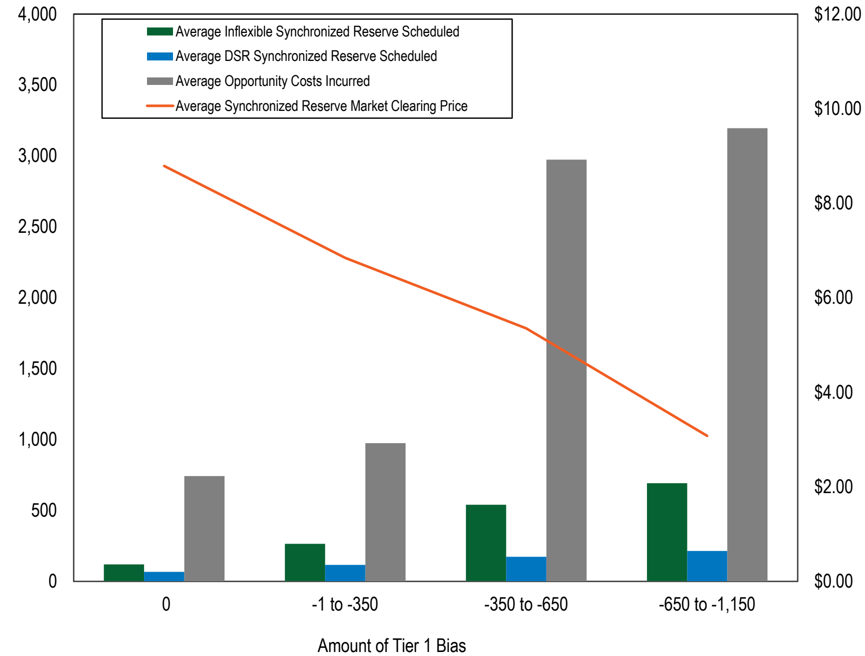
Figure 9-14 Impact of flexible Tier 2 synchronized reserve added by IT SCED and RT SCED to the Mid-Atlantic Dominion Sub-Zone: January through March 2013



Each market clearing engine (ASO, IT SCED, and RT SCED) can have its Tier 1 estimate manually biased. ASO Tier 1 biasing was used in 590 hours. In 585 hours the biasing was negative, ranging from -2,000 MW to -100 MW, with an average of -577 MW. IT SCED Tier 1 biasing was not used for the first quarter of 2013. RT SCED Tier 1 biasing occurred between January 22 and February 1 (with one hour in March 2) for a total of 48 hours, averaging 530 MW. In every hour which RT SCED Tier 1 biasing was used, it was used to add Tier 1 to the estimate, thereby lessening the need to schedule additional Tier 2 synchronized reserve.

PJM gives several reasons for Tier 1 biasing. Sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, sometimes system conditions change rapidly during the hour between a market solution and the actual hour.

Figure 9-15 Impact of Tier 1 Bias the ASO solution on SRMCP, MW Scheduled, and LOC Charges: January – March 2013



The MMU recommends that PJM be more explicit about why Tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available Tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

History of Spinning Events

Spinning events (Table 9-20) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[32] The

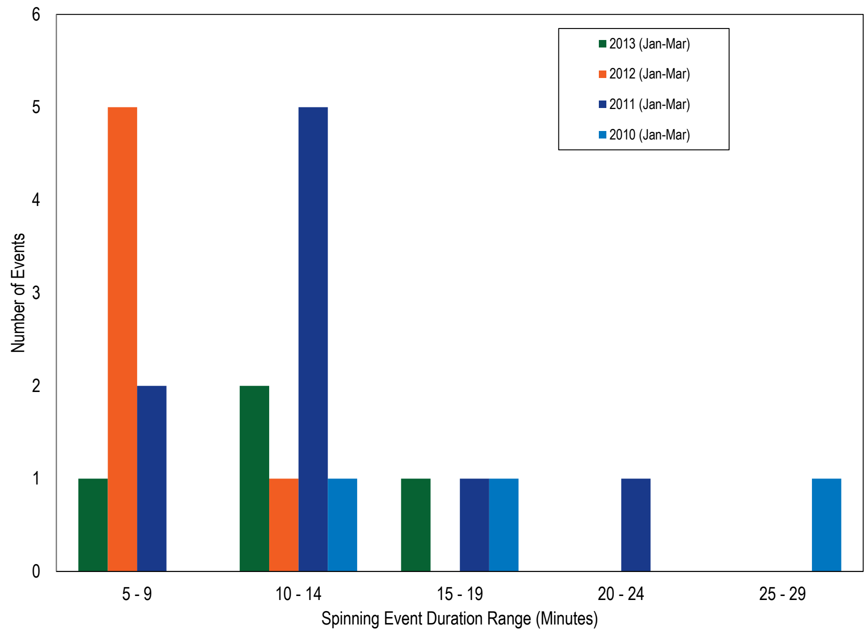
32 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

reserve remains loaded until system balance is recovered. From January 2010 through March 2013, PJM experienced 95 spinning events, or between two and three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.2 minutes.

Table 9-20 Spinning Events, January 2010 through March 2013

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6			
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10			
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9			
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8			
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16			
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7			
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7			
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7			
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18			
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10			
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12			
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7			
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10			
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19			
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Figure 9-16 Spinning events duration distribution curve, January through March 2010 to 2013



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. No primary reserve shortages occurred between January 1, 2013 and March 31, 2013.

Non-Synchronized Reserve Market

The primary reserve requirement is 150 percent of the largest contingency. For the RTO Reserve Zone this is 2,063 MW. For the Mid-Atlantic Dominion Reserve Zone this is 1,700 MW. The primary reserve requirement can be filled with Tier 1 synchronized reserve, Tier 2 synchronized reserve, or non-synchronized reserve subject to the requirement that there be 1,300 MW of synchronized reserve in the Mid-Atlantic Dominion Reserve Zone. The Ancillary Services Optimizer determines the most economic combination of these products to fill the balance of the primary reserve requirement. As such there is no pre-defined hourly requirement for non-synchronized reserve.

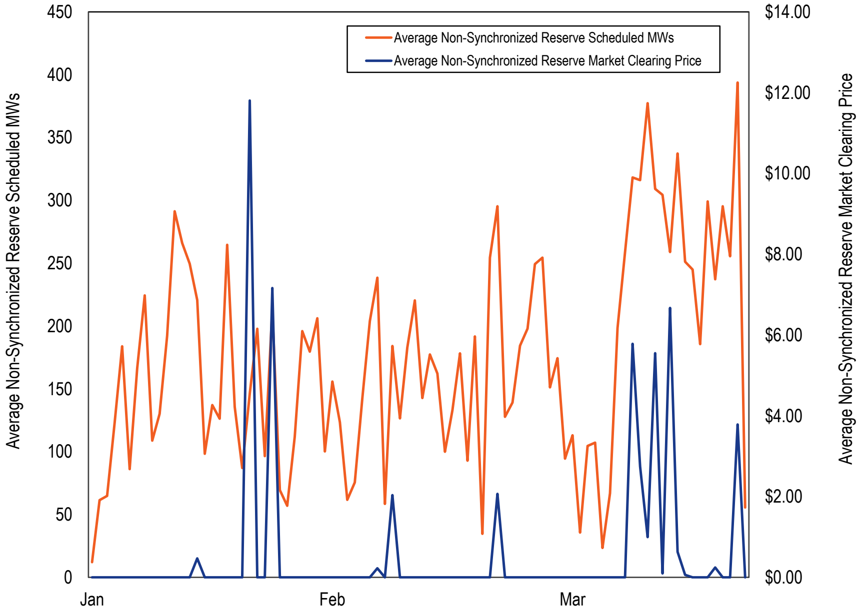
Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The remainder can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.[33]

Like Tier 1 synchronized reserve PJM calculates the amount of non-synchronized reserve available each hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 9-17 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market clearing price was greater than zero in 58 hours (five percent of all hours) from January through March of 2013 with a maximum of $128.70 on January 22, 2013.The non-synchronized reserve market clearing price for the RTO Reserve Zone never cleared for greater than $0.

33 PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 59 (April 1, 2013), p. 86.

Figure 9-17 Daily average Non-Synchronized Reserve Market clearing price and MW cleared: January through March 2013



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.[34]

The DASR 30-minute reserve requirements are determined by the reliability region.[35] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[36] 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

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[37] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2012 the load forecast error increased from 1.97 percent to 2.13 percent. The forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,817 MW per hour for January through March 2013, a slight decrease from 6,841 MW per hour in 2012.

In January through March, 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test, calculated by the MMU, in January through March, 2012.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand side resources cleared the DASR market in January through March, 2013.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[38] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but calculated by PJM. As of March 31, 2013, 13 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

34 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
35 PJM. "Manual 13, Emergency Requirements," Revision 52 (February 1, 2013), pp. 12-13.
36 PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.

37 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
38 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 59 (April 1, 2013), p. 144-145.

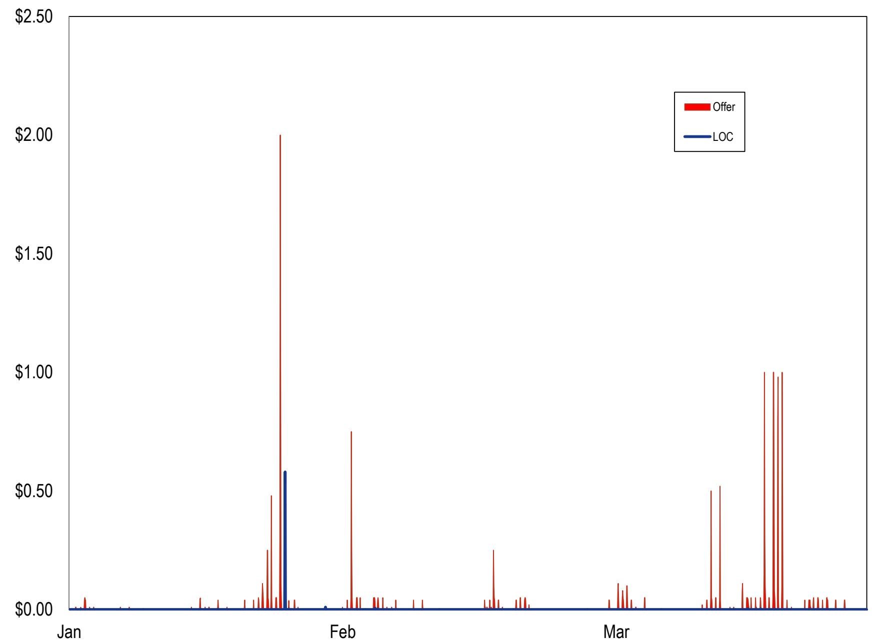
Market Performance

For 90 percent of hours in January through March, 2013, DASR cleared at a price of $0.00 (Figure 9-18). From January through March 2013, the weighted DASR price was $0.01. The highest price was $2.00 on January 24, 2013. 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. Most (93 percent) DASR clearing prices consist solely of the offer price. The breakdown of price into offer and LOC is in Figure 9 17.

Table 9-21 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2011 through March 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	$45,885
2011	Apr	5,265	$0.00	$0.05	$0.01	$24,463
2011	May	5,554	$0.00	$25.52	$0.29	$894,607
2011	Jun	7,305	$0.00	$193.97	$2.26	$9,653,815
2011	Jul	8,647	$0.00	$217.12	$4.21	$22,880,723
2011	Aug	7,787	$0.00	$61.91	$0.75	$3,577,433
2011	Sep	6,535	$0.00	$5.00	$0.07	$292,252
2011	Oct	5,874	$0.00	$0.04	$0.00	$3,655
2011	Nov	6,067	$0.00	$0.04	$0.00	$6,155
2011	Dec	6,532	$0.00	$0.21	$0.00	$6,181
2012	Jan	6,944	$0.00	$0.02	$0.00	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	$5,975
2013	Jan	6,963	$0.00	$2.00	$0.01	$45,337
2013	Feb	6,957	$0.00	$0.75	$0.00	$20,062
2013	Mar	6,552	$0.00	$1.00	$0.02	$75,071

Figure 9-18 Hourly components of DASR clearing price: January through March 2013



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 the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

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 the costs associated with providing this service.

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. (Table 9-22)

Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. The PJM and MMU proposal for system restoration was approved at the February 28, 2013, Markets and Reliability Committee (MRC).

The proposed changes include allowing PJM more flexibility in procuring black start resources by allowing cross zonal coordination between transmission zones, clarifying the responsibility for black start resources selection, revising the timing requirement for black start from 90 minutes to three hours, and implementing a process to revise black start plans on a five year basis in order to ensure system restoration needs are met. This proposal is a substantial improvement to current system restoration strategy, which does not give PJM adequate flexibility in procuring black start resources. This proposal also clarifies that PJM is the entity responsible for selecting the appropriate black start resources for each transmission zone based on system restoration requirements.

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

In January through March 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits: $38,980) to $10.66 per MW in the AEP zone (total credits: $22,352,763). For each zone, Table 9-22 shows black start revenue requirement credits, black start operating reserve credits, and the black start rate (calculated as credits per MW).

Table 9-22 Black start zonal credits for network transmission use: January through March 2013

Zone	Revenue Requirement Credits	Operating Reserve Credits	Black Start Rate ($/MW)
AECO	$136,178		$0.54
AEP	$160,578	$22,192,186	$10.66
AP	$51,913		$0.07
ATSI	$38,980		$0.03
BGE	$2,055,089	$2,500	$3.27
ComEd	$1,048,471		$0.49
DAY	$61,281	$5,530	$0.21
DEOK	$82,925		$0.17
DLCO	$15,085		$0.05
DPL	$147,659	$1,915	$0.40
JCPL	$146,258		$0.26
Met-Ed	$184,402		$0.67
PECO	$344,865	$8,515	$0.46
PENELEC	$138,744		$0.53
Pepco	$75,718		$0.13
PPL	$42,395		$0.06
PSEG	$668,315		$0.71

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).[1]

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 network as power is moved from generation to load. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and 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.

Congestion is neither good nor bad but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012.

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. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3,4]

Overview

Energy Cost

- **Total Energy Costs.** Total energy costs in the first three months of 2013 decreased by $41.5 million or 30.4 percent from the first three months of 2012, from -$136.4 million to -$177.9 million. Day-ahead net energy costs in the first three months of 2013 decreased by $79.1 million or 69.0 percent from the first three months of 2012, from -$114.6 million to -$193.8 million. Balancing net energy costs in the first three months of 2013 increased by $44.5 million or 155.5 percent from the first three months of 2012, from -$28.6 million to $15.9 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first three months of 2013 increased by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6 million. Day-ahead net marginal loss costs in the first three months of 2013 increased by $48.1 million or 19.4 percent from the first three months of 2012, from $248.1 million to $296.2 million. Balancing net marginal loss costs decreased in the first three months of 2013 by $4.8 million or 35.2 percent from the first three months of 2012, from -$13.8 million to -$18.6 million.
- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total

3 The total marginal loss and congestion results were calculated as of April 15, 2013, and are subject to change, based on continued PJM billing updates.

4 For more details on the concepts in this section, see the *2012 State of the Market Report for PJM* Section 10, "Congestion and Marginal Losses."

marginal loss costs in the first three months of 2013 ranged from $86.7 million in February to $101.1 million in January.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments that is paid back in full to load and exports on a load ratio basis.[5] The marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $63.5 million or 51.9 percent, from $122.4 million in the first three months of 2012 to $185.9 million in the first three months of 2013.[6]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $151.0 million or 83.5 percent, from $180.9 million in the first three months of 2012 to $331.9 million in the first three months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $87.5 million or 149.8 percent from -$58.4 million in the first three months of 2012 to -$145.9 million in the first three months of 2013.
- **Monthly Congestion.** Monthly congestion costs in the first three months of 2013 ranged from $48.5 million in March to $77.4 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Readington - Roseland line, the Clover and the Cloverdale transformers, and the West Interface. (Table 10-27)

5 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

6 The total zonal congestion numbers were calculated as of April 16, 2013 and are, based on continued PJM billing updates, subject to change.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first three months of 2013. Day-ahead congestion frequency increased by 49.1 percent from 54,596 congestion event hours in the first three months of 2012 to 81,378 congestion event hours in the first three months of 2013. Day-ahead, congestion-event hours decreased on the, flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.
- Real-time congestion frequency increased by 45.1 percent from 4,129 congestion event hours in the first three months of 2012 to 5,914 congestion event hours in the first three months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, the transformers, and the transmission lines.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first three months of 2013, for 45.1 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 the first three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in 2012. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.

- **Zonal Congestion.** AP was the most congested zone in the first three months of 2013. AP had -$8.3 million in total load costs, -$44.8 million in total generation credits and -$1.6 million in explicit congestion, resulting in $34.9 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The AP South interface, the Bedington transformer, the Readington – Roseland and the Dickerson - Pleasant View line, and the 5004/5005 Interface contributed $29.0 million, or 83.0 percent of the total AP Control Zone congestion costs.

The ComEd Control Zone was the second most congested zone in PJM in the first three months of 2013, with $34.3 million. The Crete - St Johns Tap flowgate contributed $4.8 million or 13.9 percent of the total ComEd Control Zone congestion cost in first three months of 2013. The AEP Control Zone was the third most congested zone in PJM in the first three months of 2013, with a cost of $25.5 million.

- **Ownership.** In the first three months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first three months of 2013, financial companies received $28.3 million in net congestion credits, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $214.2 million in net congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three months of 2012.

Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first three months of 2013 compared to the first three months of 2012. Total marginal loss costs increased in the first three months of 2013 by $43.2 million or 18.5 percent from the first three months of 2012, from $234.3 million to $277.6million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the first ten months of the 2012 to 2013 planning period, total ARR and FTR revenues offset 89.9 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period.[7] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first three months of 2009 to 2013. The load-weighted average real-time LMP increased $6.21 or 19.9 percent from $31.21 in the first three months of 2012 to $37.41 in the first three months of 2013. The load-weighted average congestion component did not change in the first three months of 2013 from the first three months of 2012, remaining at $0.02. The load-weighted average loss component increased $0.02 or 604.6 percent from $0.00 in the first three months of 2012 to $0.02 in the first three months of 2013. The load-weighted average energy component increased $6.19 or 19.9 percent from $31.18 in the first three months of 2012 to $37.37 in the first three months of 2013.

7 See the *2012 State of the Market Report for PJM* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013."

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2013

(Jan-Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first three months of 2009 through 2013. The load-weighted average day-ahead LMP increased $5.75 or 18.3 percent from $31.51 in the first three months of 2012 to $37.26 in the first three months of 2013. The load-weighted average congestion component decreased $0.01 or 18.2 percent from $0.08 in the first three months of 2012 to $0.07 in the first three months of 2013. The load-weighted average loss component increased $0.03 or 133.7 percent from -$0.03 in the first three months of 2012 to $0.01 in the first three months of 2013. The load-weighted average energy component increased $5.74 or 18.2 percent from $31.45 in the first three months of 2012 to $37.19 in the first three months of 2013. In terms of proportion of day-ahead LMP, the energy and loss components both increased, while the energy and congestion components became a smaller proportion in the first three months of 2013.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2009 through 2013

(Jan-Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for the first three months of 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 10-4 for the first three months of 2012 and 2013.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March of 2012 and 2013

	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$31.86	$31.17	($0.34)	$1.03	$38.44	$37.27	($0.43)	$1.60
AEP	$29.96	$31.10	($0.39)	($0.75)	$35.34	$37.35	($1.09)	($0.92)
AP	$31.75	$31.21	$0.34	$0.19	$36.97	$37.43	($0.41)	($0.04)
ATSI	$30.37	$31.06	($0.83)	$0.13	$35.70	$37.21	($1.73)	$0.22
BGE	$36.38	$31.30	$3.30	$1.78	$42.02	$37.59	$2.52	$1.91
ComEd	$27.87	$31.01	($1.32)	($1.82)	$31.60	$37.04	($3.36)	($2.08)
DAY	$30.53	$31.15	($0.52)	($0.10)	$35.14	$37.38	($2.13)	($0.11)
DEOK	$29.14	$31.17	($0.44)	($1.59)	$33.20	$37.35	($2.23)	($1.92)
DLCO	$29.94	$31.01	($0.31)	($0.77)	$33.77	$37.19	($2.12)	($1.30)
Dominion	$33.01	$31.38	$1.19	$0.44	$40.68	$37.69	$2.54	$0.45
DPL	$35.06	$31.28	$2.23	$1.54	$39.53	$37.63	($0.39)	$2.28
JCPL	$32.13	$31.31	($0.36)	$1.18	$40.33	$37.43	$1.10	$1.80
Met-Ed	$31.39	$31.25	($0.35)	$0.49	$38.12	$37.46	($0.06)	$0.72
PECO	$31.53	$31.22	($0.42)	$0.73	$37.23	$37.35	($1.20)	$1.08
PENELEC	$31.04	$31.15	($0.63)	$0.53	$38.10	$37.29	$0.30	$0.52
Pepco	$35.23	$31.33	$2.69	$1.21	$42.05	$37.62	$3.05	$1.39
PPL	$31.19	$31.27	($0.53)	$0.44	$37.61	$37.46	($0.51)	$0.66
PSEG	$32.25	$31.15	($0.15)	$1.26	$47.59	$37.21	$8.88	$1.50
RECO	$32.00	$31.31	($0.43)	$1.12	$53.46	$37.33	$14.74	$1.39
PJM	$31.21	$31.18	$0.02	$0.00	$37.41	$37.37	$0.02	$0.02

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March of 2012 and 2013

	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$32.54	$31.48	$0.10	$0.96	$38.64	$37.26	($0.30)	$1.68
AEP	$30.33	$31.41	($0.24)	($0.83)	$34.99	$37.19	($1.27)	($0.92)
AP	$31.92	$31.53	$0.23	$0.16	$36.49	$37.24	($0.75)	$0.01
ATSI	$30.58	$31.33	($0.71)	($0.04)	$35.53	$37.14	($1.66)	$0.05
BGE	$36.54	$31.59	$3.04	$1.91	$41.70	$37.33	$2.52	$1.85
ComEd	$27.84	$31.32	($1.55)	($1.93)	$31.83	$37.00	($2.82)	($2.36)
DAY	$30.83	$31.46	($0.35)	($0.28)	$35.36	$37.28	($1.74)	($0.18)
DEOK	$29.17	$31.33	($0.18)	($1.99)	$33.41	$37.09	($1.91)	($1.77)
DLCO	$30.54	$31.33	$0.06	($0.85)	$33.48	$37.11	($2.34)	($1.28)
Dominion	$33.49	$31.66	$1.24	$0.59	$40.25	$37.48	$2.32	$0.45
DPL	$34.86	$31.56	$1.53	$1.77	$39.53	$37.28	($0.12)	$2.37
JCPL	$32.77	$31.59	$0.11	$1.07	$40.62	$37.28	$1.32	$2.02
Met-Ed	$31.55	$31.36	($0.21)	$0.40	$38.03	$37.06	$0.25	$0.72
PECO	$32.01	$31.49	($0.16)	$0.69	$37.56	$37.10	($0.68)	$1.14
PENELEC	$31.53	$31.35	($0.52)	$0.70	$38.25	$37.13	$0.30	$0.82
Pepco	$35.60	$31.52	$2.46	$1.62	$41.64	$37.22	$3.02	$1.39
PPL	$31.43	$31.49	($0.36)	$0.30	$37.66	$37.15	($0.09)	$0.60
PSEG	$32.90	$31.49	$0.15	$1.26	$46.55	$37.20	$7.51	$1.85
RECO	$32.38	$31.47	($0.23)	$1.13	$50.35	$37.27	$11.50	$1.58
PJM	$31.51	$31.45	$0.08	($0.03)	$37.26	$37.19	$0.07	$0.01

Component Costs

Table 10-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first three months of 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 10-5 Total PJM costs by component (Dollars (Millions)): January through March of 2009 through 2013[8]

	Component Costs (Millions)					
(Jan-Mar)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($218)	$454	$307	$543	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$360	$560	$9,584	5.8%
2012	($136)	$234	$122	$220	$6,938	3.2%
2013	($178)	$278	$186	$286	$7,762	3.7%

8 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP (SMP). Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.[9]

The total energy cost for the first three months of 2013 was -$177.9 million, which was comprised of load energy payments of $10,357.2 million, generation energy credits of $10,535.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$0.0 million. The monthly energy costs for the first three months of 2013 ranged from -$63.0 million in January to -$54.8 million in February.

Total Energy Costs

Table 10-6 shows total energy component costs and total PJM billing, for the first three months of 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

9 Net residual adjustments are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Table 10-6 Total PJM costs by energy component (Dollars (Millions)): January through March of 2009 through 2013[10]

(Jan-Mar)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($218)	NA	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)

Energy costs for the first three months of 2009 through 2013 are shown in Table 10-7 and Table 10-8. Table 10-7 shows PJM energy costs by category for the first three months of 2009 through 2013 and Table 10-8 shows PJM energy costs by market category for the first three months of 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-6.

Table 10-7 Total PJM energy costs by category (Dollars (Millions)): January through March of 2009 through 2013

	Energy Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)

Table 10-8 Total PJM energy costs by market category (Dollars (Millions)): January through March of 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.8)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)

10 The Energy Costs include net inadvertent charges.

Monthly Energy Costs

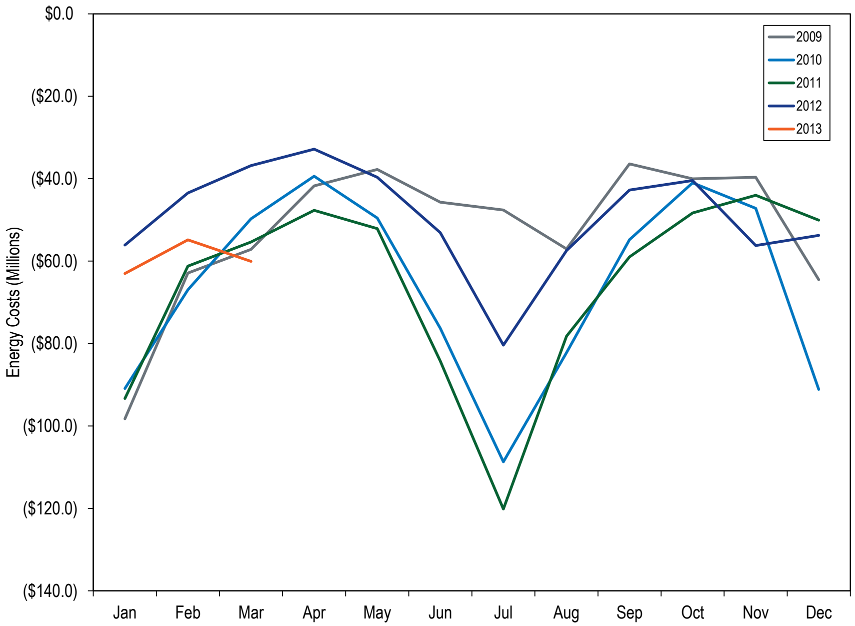
Table 10-9 shows a monthly summary of energy costs by type for the first three months of 2012 and 2013.

Table 10-9 Monthly energy costs by type (Dollars (Millions)): January through March of 2012 and 2013

	Energy Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.1)
Total	($114.6)	($28.6)	$6.8	($136.4)	($193.8)	$15.9	($0.0)	($177.9)

Figure 10-1 shows PJM monthly energy costs of January 2009 through March 2013.

Figure 10-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through March 2013



Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost 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.

Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to 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.

The total marginal loss cost in PJM for the first three months of 2013 was $277.6 million, which was comprised of load loss payments of $8.0 million, generation loss credits of -$277.8 million, explicit loss costs of -$8.2 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first three months of 2013 ranged from $86.7 million in February to $101.1 million in January. Marginal loss credits increased in the first three months of 2013 by $1.8 million or 1.8 percent from the first three months of 2012, from $97.7 million to $99.4 million.

Total Marginal Loss Costs

Table 10-10 shows the total marginal loss component costs for the first three months of 2009 through 2013. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

Table 10-10 Total PJM costs by loss component (Dollars (Millions)): January through March of 2009 through 2013[11,12]

(Jan-Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$454	NA	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%

11 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.
12 The Loss Costs include net inadvertent charges.

Total marginal loss costs for the first three months of 2009 through 2013 are shown in Table 10-11 and Table 10-12. Table 10-11 shows PJM total marginal loss costs by category for the first three months of 2009 through 2013. Table 10-12 shows PJM total marginal loss costs by market category for the first three months of 2009 through 2013.

Table 10-11 Total PJM marginal loss costs by category (Dollars (Millions)): January through March of 2009 through 2013

	Marginal Loss Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6

Table 10-12 Total PJM marginal loss costs by market category (Dollars (Millions)): January through March of 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6

Monthly Marginal Loss Costs

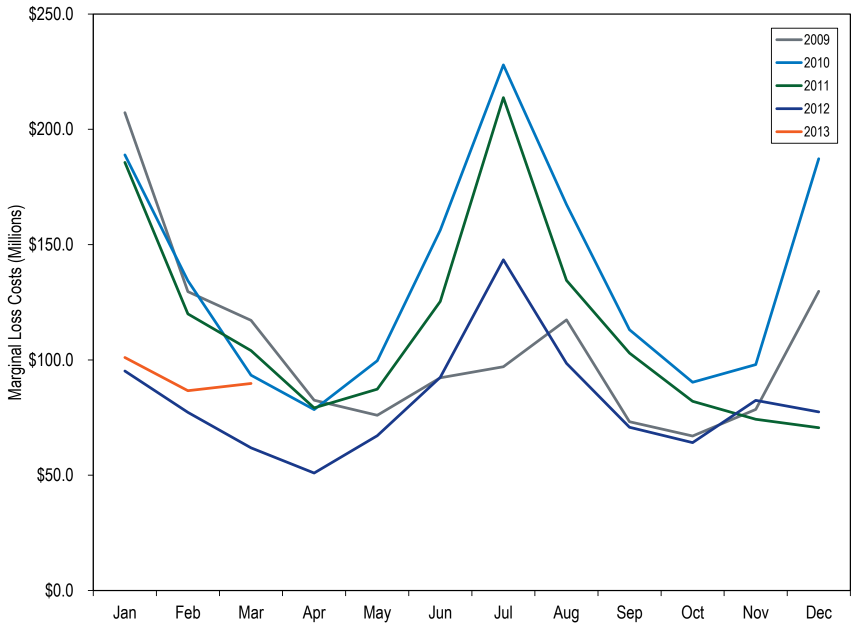
Table 10-13 shows a monthly summary of marginal loss costs by type for the first three months of 2012 and 2013.

Table 10-13 Monthly marginal loss costs by type (Dollars (Millions)): January through March of 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Total	$248.1	($13.8)	$0.0	$234.3	$296.2	($18.6)	($0.0)	$277.6

Figure 10-2 shows PJM monthly marginal loss costs of January 2009 through March 2013.

Figure 10-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through March of 2013



Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (generation energy credits less load energy payments) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 10-14 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first three months of 2009 through 2013.

Table 10-14 Marginal loss credits (Dollars (Millions)): January through March, 2009 through 2013[13]

Loss Credit Accounting (Millions)				
(Jan-Mar)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($218.3)	$454.0	$0.9	$236.6
2010	($207.6)	$416.6	($0.0)	$208.9
2011	($209.9)	$409.6	$0.5	$200.1
2012	($136.4)	$234.3	($0.2)	$97.7
2013	($177.9)	$277.6	($0.3)	$99.4

Congestion

Congestion Accounting

Total congestion costs in PJM in the first three months of 2013 were $185.9 million, which was comprised of load congestion payments of $37.4 million, generation credits of -$166.7 million and explicit congestion of -$18.2 million (Table 10-16).

Total Congestion

Table 10-15 shows total congestion from January through March by year from 2008 through 2013.[14]

13 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.
14 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 PJM congestion (Dollars (Millions)): January through March, 2008 to 2013

	Congestion Costs (Millions)			
(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$485.6	NA	$7,718.0	6.3%
2009	$306.9	(36.8%)	$7,515.0	4.1%
2010	$344.9	12.4%	$8,415.0	4.1%
2011	$359.9	4.3%	$9,584.0	3.8%
2012	$122.4	(66.0%)	$6,938.0	1.8%
2013	$185.9	51.9%	$7,762.0	2.4%

Table 10-16 Total PJM congestion costs by category (Dollars (Millions)): January through March, 2008 to 2013

	Congestion Costs (Millions)				
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$286.4	($190.5)	$8.7	$0.0	$485.6
2009	$106.0	($227.3)	($26.5)	$0.0	$306.9
2010	$80.1	($281.0)	($16.2)	$0.0	$344.9
2011	$198.1	($199.0)	($37.2)	$0.0	$359.9
2012	$16.8	($120.1)	($14.5)	$0.0	$122.4
2013	$37.4	($166.7)	($18.2)	$0.0	$185.9

Table 10-17 Total PJM congestion costs by market category (Dollars (Millions)): January through March, 2008 to 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Mar)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	$0.0	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	$0.0	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$48.2	($235.8)	$47.8	$331.9	($10.8)	$69.1	($66.0)	($145.9)	$0.0	$185.9

Total congestion costs in Table 10-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO[15] and those M2M flowgates in the NYISO.[16]

Table 10-16 shows the congestion costs by category for the first three months of 2013. The January through March 2013 PJM total congestion costs were comprised of $37.4 million in load congestion payments, -$166.7 million in generation congestion credits, and -$18.2 million in explicit congestion costs.

15 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://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2013).

16 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Monthly Congestion

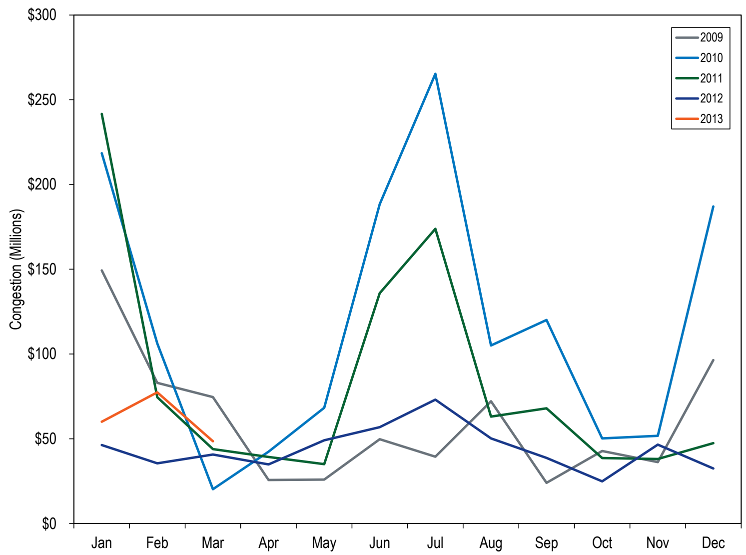
Table 10-18 shows that during the first three months of 2012 and 2013, monthly congestion costs ranged from $48.5 million to $77.4 million in 2013. Table 10-18 shows the monthly congestion costs in the first three months of 2013 were higher than in the first three months of 2012.

Table 10-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through March, 2012 to 2013

	Congestion Costs (Millions)							
	2012 (Jan-Mar)				2013 (Jan-Mar)			
	Day-Ahead Total	Balancing Total	Inadvertent charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.1)	$0.0	$40.7	$69.9	($21.4)	$0.0	$48.5
Total	$180.9	($58.4)	$0.0	$122.4	$331.9	($145.9)	$0.0	$185.9

Figure 10-3 shows PJM monthly congestion for January 2009 through March 2013.

Figure 10-3 PJM monthly congestion (Dollars (Millions)): January 2009 to March 2013



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 the first months of 2013, there were 81,378 day-ahead, congestion-event hours compared to 54,596 day-ahead, congestion-event hours in the first three months of 2012. In the first three months of 2013, there were 5,914 real-time, congestion-event hours compared to 4,129 real-time, congestion-event hours in the first three months of 2012.

During the first three months of 2013, for only 3.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first three months of 2013, for 45.1 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 the first three months of 2013. With $81.8 million in total congestion costs, it accounted for 44.0 percent of the total PJM congestion costs in the first three months of 2013. The top five constraints in terms of congestion costs together contributed $72.8 million, or 39.2 percent, of the total PJM congestion costs in the first three months of 2013. The top five constraints were the AP South and West interfaces, the Readington – Roseland transmission line, and Clover and Cloverdale transformers.

Congestion by Facility Type and Voltage

In the first three months of 2013, compared to the first three months of 2012, day-ahead, congestion-event hours decreased on the flowgates, while congestion frequency on internal PJM interfaces, transmission lines and transformers decreased. Real-time, congestion-event hours increased on the flowgates, the interfaces, and the transformers, while congestion frequency on the transmission lines decreased.

Day-ahead congestion costs decreased on the flowgates in the first three months of 2013 compared to the first three months of 2012 and increased on PJM interfaces, transmission lines and transformers in the first three months of 2013 compared to the first three months of 2012. Balancing congestion costs increased on the flowgates and decreased on transformers, transmission lines and the interfaces in the first three months of 2013 compared to the first three months of 2012.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17,18] For comparison, this information is presented in Table 10-20 for the first three months of 2012.[19]

Table 10-19 Congestion summary (By facility type): January through March 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($5.9)	($39.4)	$6.6	$40.1	$1.3	$7.1	($18.2)	($23.9)	$16.2	5,478	2,328
Interface	$69.4	($44.2)	($1.0)	$112.5	$7.0	$14.7	$1.8	($6.0)	$106.6	3,571	615
Line	$11.8	($93.6)	$24.4	$129.8	($12.1)	$44.6	($38.5)	($95.2)	$34.6	47,059	2,472
Other	$2.8	($1.8)	$5.1	$9.7	($0.0)	$0.0	$0.0	($0.0)	$9.7	4,443	5
Transformer	$6.9	($14.9)	$7.7	$29.5	($2.2)	$6.3	($10.3)	($18.8)	$10.7	20,827	494
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,914

Table 10-20 Congestion summary (By facility type): January through March 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($13.6)	($48.4)	$12.2	$47.0	$0.5	$2.6	($28.8)	($30.9)	$16.1	7,023	1,576
Interface	$12.2	($25.4)	($0.2)	$37.5	$2.3	$3.5	($2.2)	($3.5)	$34.0	1,649	179
Line	$21.3	($41.8)	$12.5	$75.6	($6.5)	$4.7	($10.3)	($21.4)	$54.1	32,682	1,932
Other	$1.0	($0.9)	($0.1)	$1.8	($0.7)	($0.0)	$0.2	($0.5)	$1.4	819	203
Transformer	$2.2	($13.2)	$2.7	$18.1	$0.1	$1.3	($0.7)	($1.8)	$16.2	12,423	239
Unclassified	$0.3	($0.2)	$0.4	$0.9	($0.1)	$0.1	($0.2)	($0.3)	$0.6	NA	NA
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$122.4	54,596	4,129

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 the first three months of 2013, there were 81,378 congestion event hours in the Day-Ahead Market. Among those, only 2,519 (3.1 percent) were also constrained in the Real-Time Market. In the first three months of 2012, among the 54,596 day-ahead congestion event hours, only 1,915 (3.5 percent) were binding in the Real-Time Market.[20]

17 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

18 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

19 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.

20 Constraints are mapped to transmission facilities. In the Day-Ahead Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In the first three months of 2013, there were 5,861 congestion event hours in the Real-Time Market. Among these, 2,635 (45.0 percent) were also constrained in the Day-Ahead Market. In the first three months of 2012, among the 4,129 real-time congestion event hours, only 1,907 (46.2 percent) were binding in the day-ahead.

Table 10-21 Congestion Event Hours (Day Ahead against Real Time): January through March 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Mar)			2013 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	7,023	721	10.3%	5,478	907	16.6%
Interface	1,649	77	4.7%	3,571	509	14.3%
Line	32,682	980	3.0%	47,059	895	1.9%
Other	819	47	5.7%	4,443	5	0.1%
Transformer	12,423	90	0.7%	20,827	203	1.0%
Total	54,596	1,915	3.5%	81,378	2,519	3.1%

Table 10-22 Congestion Event Hours (Real Time against Day Ahead): January through March 2012 to 2013

	Congestion Event Hours					
	2012 (Jan - Mar)			2013 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,576	759	48.2%	2,328	1,041	44.7%
Interface	179	77	43.0%	615	525	85.4%
Line	1,932	934	48.3%	2,472	896	36.2%
Other	203	47	23.2%	5	5	100.0%
Transformer	239	90	37.7%	494	202	40.9%
Total	4,129	1,907	46.2%	5,914	2,669	45.1%

Table 10-23 shows congestion costs by facility voltage class for the first three months of 2013. In comparison to the first three months of 2012 (shown in Table 10-24), congestion costs decreased across 345 kV, 230 kV, 161 kV and 138 kV in the first three months of 2013.

Table 10-23 Congestion summary (By facility voltage): January through March 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$5.2	($2.9)	$3.7	$11.8	$0.0	$0.0	$0.0	$0.0	$11.8	2,027	0
500	$72.5	($49.3)	($0.5)	$121.3	$8.7	$15.1	($1.6)	($8.1)	$113.2	4,454	724
345	($4.1)	($27.8)	$6.7	$30.4	($1.3)	$8.7	($15.3)	($25.3)	$5.1	12,864	1,545
230	$11.9	($74.4)	$22.0	$108.2	($11.0)	$43.1	($30.9)	($85.0)	$23.2	15,851	1,330
161	($1.7)	($3.1)	($0.6)	$0.8	($0.4)	$0.2	($0.1)	($0.7)	$0.1	654	403
138	$0.6	($33.2)	$10.2	$44.1	($0.5)	$4.4	($16.4)	($21.4)	$22.7	34,864	1,668
115	($0.0)	($2.8)	$0.6	$3.3	($0.3)	$0.4	($0.1)	($0.8)	$2.5	3,366	185
69	$0.5	($0.3)	$0.7	$1.6	($1.2)	$0.7	($0.7)	($2.6)	($1.0)	4,394	59
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2,893	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	NA	NA
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$185.9	81,378	5,914

Table 10-24 Congestion summary (By facility voltage): January through March 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($1.6)	$1.2	$2.7	$0.1	($0.0)	($0.1)	($0.0)	$2.7	874	69
500	$13.0	($29.7)	$0.2	$42.9	$2.0	$4.7	($2.6)	($5.3)	$37.6	3,107	237
345	($8.7)	($32.4)	$5.1	$28.9	$0.8	$1.2	($12.8)	($13.2)	$15.6	8,368	684
230	$18.3	($13.2)	$0.1	$31.6	($1.2)	$1.4	$0.9	($1.7)	$29.9	8,794	1,010
161	($3.9)	($6.3)	$3.3	$5.7	($0.3)	$0.2	($4.4)	($4.9)	$0.8	1,342	344
138	($3.2)	($46.8)	$16.3	$60.0	($1.2)	$4.2	($22.0)	($27.4)	$32.6	26,513	1,554
115	$2.4	$0.1	$0.3	$2.6	($0.4)	$0.2	($0.0)	($0.7)	$2.0	3,203	89
69	$5.3	$0.3	$0.5	$5.5	($4.0)	$0.1	($0.9)	($5.0)	$0.5	2,391	142
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
Unclassified	$0.3	($0.2)	$0.4	$0.9	($0.1)	$0.1	($0.2)	($0.3)	$0.6	NA	NA
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$122.4	54,596	4,129

Constraint Duration

Table 10-25 lists constraints in the first three months of 2012 and 2013 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from the first three month of 2012 to the first three months of 2013.

Table 10-25 Top 25 constraints with frequent occurrence: January through March 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	2,257	3,174	917	0	0	0	26%	36%	10%	0%	0%	0%
2	Gould Street - Westport	Line	0	2,893	2,893	0	0	0	0%	33%	33%	0%	0%	0%
3	Readington - Roseland	Line	1	1,925	1,924	0	609	609	0%	22%	22%	0%	7%	7%
4	AP South	Interface	881	2,012	1,131	73	505	432	10%	23%	13%	1%	6%	5%
5	Devon - Skokie	Line	17	1,697	1,680	0	0	0	0%	19%	19%	0%	0%	0%
6	Howard - Shelby	Line	945	1,638	693	0	0	0	11%	19%	8%	0%	0%	0%
7	Prairie State - W Mt. Vernon	Flowgate	387	897	510	110	692	582	4%	10%	6%	1%	8%	7%
8	Haurd - Steward	Line	435	1,533	1,098	0	0	0	5%	17%	12%	0%	0%	0%
9	Tanners Creek	Transformer	0	1,458	1,458	0	0	0	0%	17%	17%	0%	0%	0%
10	Monticello - East Winamac	Flowgate	812	998	186	295	387	92	9%	11%	2%	3%	4%	1%
11	West Moulton-City Of St. Marys	Line	0	1,374	1,374	0	0	0	0%	16%	16%	0%	0%	0%
12	Zion	Line	1	1,326	1,325	0	0	0	0%	15%	15%	0%	0%	0%
13	Waldwick - Waldwick	Other	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
14	Bridgewater - Middlesex	Line	237	1,037	800	1	150	149	3%	12%	9%	0%	2%	2%
15	Braidwood	Transformer	0	1,168	1,168	0	0	0	0%	13%	13%	0%	0%	0%
16	Nelson - Cordova	Line	36	1,112	1,076	0	3	3	0%	13%	12%	0%	0%	0%
17	Oak Grove - Galesburg	Flowgate	1,342	654	(688)	344	362	18	15%	7%	(8%)	4%	4%	0%
18	Hudson	Other	0	971	971	0	0	0	0%	11%	11%	0%	0%	0%
19	Danville - East Danville	Line	200	943	743	0	0	0	2%	11%	8%	0%	0%	0%
20	Preston - Tanyard	Line	0	928	928	0	0	0	0%	11%	11%	0%	0%	0%
21	Rockport Works	Transformer	0	927	927	0	0	0	0%	11%	11%	0%	0%	0%
22	Loretto	Transformer	75	901	826	0	0	0	1%	10%	9%	0%	0%	0%
23	Huntingdon - Huntingdon1	Line	1,138	878	(260)	0	0	0	13%	10%	(3%)	0%	0%	0%
24	Breed - Wheatland	Flowgate	500	724	224	172	148	(24)	6%	8%	3%	2%	2%	(0%)
25	Linden - VFT	Line	913	840	(73)	0	0	0	10%	10%	(1%)	0%	0%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through March 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Gould Street - Westport	Line	0	2,893	2,893	0	0	0	0%	33%	33%	0%	0%	0%
2	Readington - Roseland	Line	1	1,925	1,924	0	609	609	0%	22%	22%	0%	7%	7%
3	Graceton - Raphael Road	Line	1,416	0	(1,416)	407	0	(407)	16%	0%	(16%)	5%	0%	(5%)
4	Devon - Skokie	Line	17	1,697	1,680	0	0	0	0%	19%	19%	0%	0%	0%
5	AP South	Interface	881	2,012	1,131	73	505	432	10%	23%	13%	1%	6%	5%
6	Tanners Creek	Transformer	0	1,458	1,458	0	0	0	0%	17%	17%	0%	0%	0%
7	West Moulton-City Of St. Marys	Line	0	1,374	1,374	0	0	0	0%	16%	16%	0%	0%	0%
8	Zion	Line	1	1,326	1,325	0	0	0	0%	15%	15%	0%	0%	0%
9	Belmont	Transformer	1,274	0	(1,274)	49	0	(49)	15%	0%	(15%)	1%	0%	(1%)
10	Waldwick - Waldwick	Other	0	1,315	1,315	0	0	0	0%	15%	15%	0%	0%	0%
11	Wolfcreek	Transformer	1,197	0	(1,197)	9	0	(9)	14%	0%	(14%)	0%	0%	(0%)
12	Braidwood	Transformer	0	1,168	1,168	0	0	0	0%	13%	13%	0%	0%	0%
13	Conesville	Transformer	1,113	0	(1,113)	0	0	0	13%	0%	(13%)	0%	0%	0%
14	Haurd - Steward	Line	435	1,533	1,098	0	0	0	5%	17%	12%	0%	0%	0%
15	Prairie State - W Mt. Vernon	Flowgate	387	897	510	110	692	582	4%	10%	6%	1%	8%	7%
16	Nelson - Cordova	Line	36	1,112	1,076	0	3	3	0%	13%	12%	0%	0%	0%
17	Rockwell - Crosby	Line	1,321	250	(1,071)	0	0	0	15%	3%	(12%)	0%	0%	0%
18	Hudson	Other	0	971	971	0	0	0	0%	11%	11%	0%	0%	0%
19	Bridgewater - Middlesex	Line	237	1,037	800	1	150	149	3%	12%	9%	0%	2%	2%
20	Preston - Tanyard	Line	0	928	928	0	0	0	0%	11%	11%	0%	0%	0%
21	Rockport Works	Transformer	0	927	927	0	0	0	0%	11%	11%	0%	0%	0%
22	Conesville	Transformer	1,060	137	(923)	0	0	0	12%	2%	(11%)	0%	0%	0%
23	Sporn	Transformer	2,257	3,174	917	0	0	0	26%	36%	10%	0%	0%	0%
24	Silver Lake - Pleasant Valley	Line	841	13	(828)	0	0	0	10%	0%	(9%)	0%	0%	0%
25	Loretto	Transformer	75	901	826	0	0	0	1%	10%	9%	0%	0%	0%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for the periods January through March 2013 and 2012.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): January through March 2013

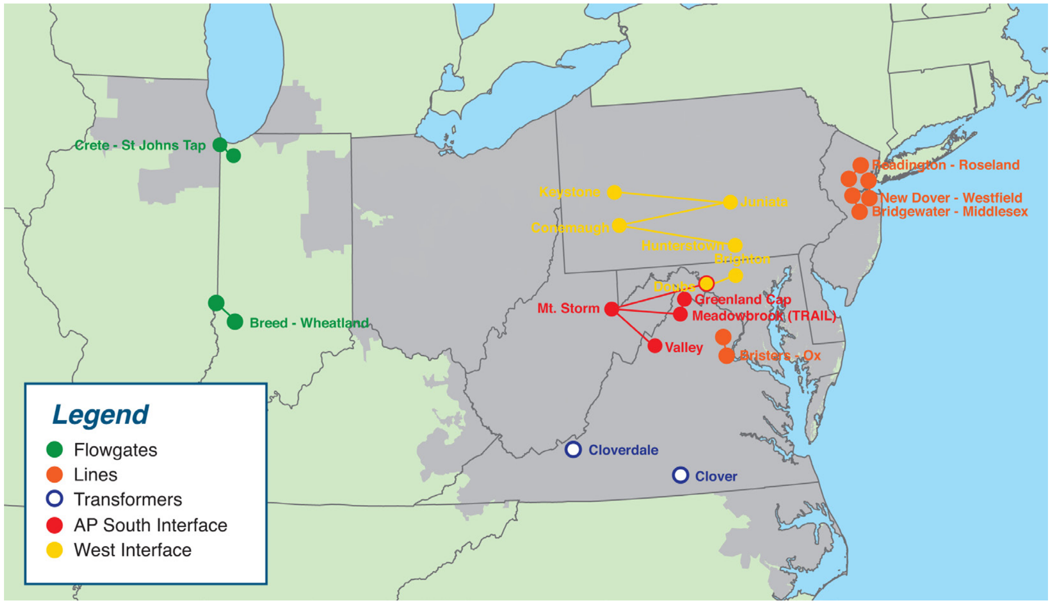
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan - Mar)
1	AP South	Interface	500	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	44.0%
2	Readington - Roseland	Line	PSEG	$1.5	($41.1)	$8.5	$51.2	($10.7)	$37.0	($21.4)	($69.1)	($17.9)	(9.6%)
3	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.1)	$5.2	($6.4)	($11.7)	($11.7)	(6.3%)
4	Cloverdale	Transformer	AEP	$5.2	($2.6)	$3.1	$10.9	$0.0	$0.0	$0.0	$0.0	$10.9	5.9%
5	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	5.2%
6	Bridgewater - Middlesex	Line	PSEG	$0.0	($13.3)	$1.0	$14.3	($0.0)	$3.5	($1.2)	($4.7)	$9.6	5.1%
7	Unclassified	Unclassified	Unclassified	$0.1	($5.2)	$5.0	$10.3	($0.6)	$0.6	($0.8)	($2.0)	$8.2	4.4%
8	Crete - St Johns Tap	Flowgate	MISO	($0.4)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	4.1%
9	New Dover - Westfield	Line	PSEG	$0.6	($5.6)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	3.8%
10	Bristers - Ox	Line	Dominion	$2.4	($2.5)	$0.4	$5.4	$0.8	$0.3	($0.3)	$0.1	$5.5	3.0%
11	Breed - Wheatland	Flowgate	MISO	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	2.9%
12	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	2.7%
13	Bedington	Transformer	AP	$1.7	($2.9)	$0.1	$4.7	$0.1	$0.1	$0.0	$0.0	$4.8	2.6%
14	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	2.5%
15	Dickerson - Pleasant View	Line	Pepco	$0.6	($3.1)	$1.2	$5.0	$0.4	$0.9	($1.1)	($1.6)	$3.4	1.8%
16	Amos	Transformer	AEP	$0.6	($2.6)	$1.1	$4.2	($2.5)	$1.1	($3.8)	($7.4)	($3.2)	(1.7%)
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	1.7%
18	Waldwick - Waldwick	Other	PSEG	$0.0	($1.4)	$1.5	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1.6%
19	Maywood - Saddlebrook	Line	PSEG	$0.0	($0.0)	$0.1	$0.2	($0.0)	$0.5	($2.6)	($3.1)	($3.0)	(1.6%)
20	Crete - St Johns	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.1	$0.6	($2.5)	($2.9)	($2.9)	(1.6%)
21	Monticello - East Winamac	Flowgate	MISO	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	1.5%
22	Bagley - Graceton	Line	BGE	$1.9	($0.7)	($0.0)	$2.6	($0.2)	($0.0)	$0.4	$0.3	$2.8	1.5%
23	Hudson	Other	PSEG	$2.1	$2.2	$3.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1.5%
24	Huntingdon - Huntingdon1	Line	AP	($0.7)	($4.2)	($0.9)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	1.4%
25	Essex - Essex	Other	PSEG	$0.4	($1.3)	$0.5	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1.2%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through March 2012

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012 (Jan - Mar)
1	Graceton - Raphael Road	Line	BGE	$12.8	($8.9)	($2.4)	$19.2	$0.1	$0.1	$1.3	$1.3	$20.5	16.8%
2	AP South	Interface	500	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	16.4%
3	Woodstock	Flowgate	MISO	($2.3)	($13.0)	$1.3	$12.0	$0.0	$0.0	$0.0	$0.0	$12.0	9.8%
4	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	5.1%
5	Breed - Wheatland	Flowgate	MISO	($0.7)	($4.0)	($0.0)	$3.4	$0.3	$0.3	($8.5)	($8.5)	($5.2)	(4.2%)
6	Crete - St Johns Tap	Flowgate	MISO	($2.7)	($9.7)	($0.4)	$6.5	$0.2	$0.5	($2.0)	($2.4)	$4.2	3.4%
7	Lancaster - Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.6	($0.3)	$0.6	($3.5)	($4.4)	($3.8)	(3.1%)
8	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	3.0%
9	Silver Lake - Pleasant Valley	Line	ComEd	($2.2)	($4.8)	$1.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	3.0%
10	Belmont	Transformer	AP	$0.8	($4.2)	$0.4	$5.3	($0.3)	$1.1	($0.4)	($1.8)	$3.5	2.8%
11	Electric Jct - Nelson	Line	ComEd	($0.9)	($3.1)	$1.1	$3.3	$0.0	$0.0	($0.0)	($0.0)	$3.3	2.7%
12	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	2.3%
13	Jefferson - Clifty Creek	Line	AEP	($0.1)	($1.9)	$0.8	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	2.2%
14	Kammer	Transformer	AEP	($0.8)	($3.2)	($0.3)	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	1.7%
15	Brues - West Bellaire	Line	AEP	$1.5	($0.6)	($0.3)	$1.9	($0.0)	$0.0	$0.0	($0.0)	$1.9	1.5%
16	Breed - Wheatland	Line	AEP	($0.9)	($2.6)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	1.3%
17	Burnham - Munster	Line	ComEd	($0.1)	($0.3)	$0.1	$0.3	$0.0	$0.3	($1.6)	($1.9)	($1.6)	(1.3%)
18	Monticello - East Winamac	Flowgate	MISO	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.5)	$1.5	1.3%
19	Lake Nelson - Middlesex	Line	PSEG	$1.3	$0.2	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1.2%
20	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.9)	$0.7	$4.5	($0.9)	$1.1	($4.0)	($6.0)	($1.5)	(1.2%)
21	Mazon - Mazon	Line	ComEd	($0.3)	($1.3)	$0.7	$1.8	($0.0)	($0.0)	($0.3)	($0.3)	$1.5	1.2%
22	Wolfcreek	Transformer	AEP	$0.1	($1.2)	$0.3	$1.5	($0.0)	($0.0)	($0.1)	($0.1)	$1.5	1.2%
23	Jefferson - Rockport	Line	AEP	($0.0)	($0.8)	$0.6	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1.2%
24	Potomac River	Transformer	Pepco	$1.3	$0.0	$0.1	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1.2%
25	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	1.1%

Figure 10-4 shows the locations of the top 10 constraints affecting PJM congestion costs in the first three months of 2013.

Figure 10-4 Location of the top 10 constraints affecting PJM congestion costs: January through March 2013[21]



21 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

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.[22] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[23] 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 and/or MISO took dispatch action to control during the first three months of 2013 and 2012 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 and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first three months of 2013, the Crete - St Johns Tap flowgate made the most significant contribution to positive congestion while the Volunteer - Phipps Bend flowgate made the most significant contribution to negative congestion.

22 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March 2013

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($0.4)	($5.8)	$2.2	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	773	0
2	Breed - Wheatland	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.0)	($1.0)	$5.4	724	148
3	Prairie State - W Mt. Vernon	($1.7)	($4.3)	($0.2)	$2.3	$0.0	($0.2)	$0.6	$0.8	$3.1	897	692
4	Monticello - East Winamac	($0.8)	($15.0)	$2.6	$16.8	$0.3	$4.4	($9.8)	($13.9)	$2.9	998	387
5	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
6	Oak Grove - Galesburg	($1.7)	($3.1)	($0.6)	$0.8	($0.2)	$0.1	$0.3	$0.0	$0.8	654	362
7	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.4)	($0.7)	($0.7)	0	37
8	Lanesville	($0.1)	($0.5)	$0.2	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	290	14
9	Pana North	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.5)	($0.6)	($0.6)	0	7
10	Rising	($0.4)	($1.5)	$0.6	$1.7	($0.1)	$0.1	($1.0)	($1.2)	$0.5	534	138
11	Rantoul - Rantoul Jct	($0.0)	($0.2)	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	53	0
12	Cayuga	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.3)	($0.3)	0	13
13	Miami Fort - Hebron	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	64	0
14	Reynold-Monticello	($0.1)	($0.5)	$0.2	$0.7	$0.0	$0.0	($0.5)	($0.5)	$0.2	86	51
15	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	5
16	Edwards - Kewanee	($0.0)	($0.1)	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	140	2
17	Bunsonville - Eugene	($0.1)	($0.2)	$0.0	$0.2	$0.0	($0.1)	($0.3)	($0.3)	($0.1)	24	91
18	Pawnee	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	39	0
19	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	33
20	Powerton - Lilly	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	23

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March 2012

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($2.3)	($13.0)	$1.3	$12.0	$0.0	$0.0	$0.0	$0.0	$12.0	631	0
2	Breed - Wheatland	($0.7)	($4.0)	($0.0)	$3.4	$0.3	$0.3	($8.5)	($8.5)	($5.2)	500	172
3	Crete - St Johns Tap	($2.7)	($9.7)	($0.4)	$6.5	$0.2	$0.5	($2.0)	($2.4)	$4.2	1,189	155
4	Monticello - East Winamac	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.5)	$1.5	812	295
5	Prairie State - W Mt. Vernon	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	387	110
6	Miami Fort - Hebron	($0.5)	($1.4)	$0.1	$1.1	($0.0)	($0.0)	($0.0)	($0.0)	$1.1	356	33
7	Oak Grove - Galesburg	($3.9)	($6.3)	$3.3	$5.7	($0.3)	$0.2	($4.4)	($4.9)	$0.8	1,342	344
8	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
9	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
10	Lanesville	$0.1	($0.1)	$0.4	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	236	0
11	Burnham - Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	223	0
12	Cumberland - Bush	($0.4)	($2.4)	$2.0	$4.0	$0.0	$0.5	($3.9)	($4.3)	($0.4)	646	119
13	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	5
14	Bunsonville - Eugene	($0.3)	($0.5)	$0.1	$0.3	$0.0	($0.1)	($0.1)	($0.0)	$0.3	90	34
15	Baldwin-Mt Vernon	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	137
16	Bloomton - Denoisck	($0.1)	($0.2)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	0
17	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
18	Rising	($0.0)	($0.0)	$0.0	$0.0	($0.1)	$0.0	($0.1)	($0.2)	($0.2)	4	9
19	Gibson - Petersburg	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.1	$0.1	$0.1	0	0
20	Rantoul - Rantoul Jct	($0.1)	($0.2)	$0.1	$0.2	($0.0)	($0.1)	($0.3)	($0.3)	($0.1)	56	0

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[24] Only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified as M2M Flowgates. Flowgates eligible for the M2M coordination process are called M2M Flowgates.[25]

Table 10-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first three months of 2013, and which had the greatest congestion cost impact on PJM.

Table 10-31 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through March 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central east	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	159
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	$0.0	($0.2)	($0.2)	0	9

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-32 and Table 10-33 show the 500 kV constraints impacting congestion costs in PJM for the first three months of 2013 and 2012 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.

Table 10-32 Regional constraints summary (By facility): January through March 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$62.2	($23.0)	$0.2	$85.4	$5.8	$10.8	$1.4	($3.6)	$81.8	2,012	505
2	West	Interface	500	$1.9	($8.4)	($0.6)	$9.8	$0.0	$0.0	($0.0)	($0.0)	$9.7	341	1
3	5004/5005 Interface	Interface	500	$1.0	($6.7)	($0.3)	$7.3	$1.2	$3.9	$0.4	($2.3)	$5.0	151	96
4	AEP - DOM	Interface	500	$3.0	($2.1)	($0.4)	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	609	1
5	Central	Interface	500	($0.6)	($2.7)	($0.4)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	116	0
6	Bedington - Black Oak	Interface	500	$0.9	($0.7)	$0.1	$1.7	$0.0	$0.0	($0.0)	($0.0)	$1.6	105	2
7	East	Interface	500	($0.1)	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
8	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	0	13
9	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
10	Cloverdale - Lexington	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6
11	EAST	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	4

24 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).
25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 10-33 Regional constraints summary (By facility): January through March 2012

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	881	73
2	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	241	2
3	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	160	5
4	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	131	64
5	Central	Interface	500	($0.6)	($1.2)	$0.1	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	170	2
6	AEP - DOM	Interface	500	$0.2	($0.3)	$0.1	$0.7	$0.3	$0.4	($0.1)	($0.2)	$0.5	66	31
7	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
8	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2

Congestion Costs by Physical and Financial Participants

In the first three months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges.[26] In the first three months of 2013, financial companies received $28.3 million, an increase of $8.1 million or 40.0 percent compared to the first three months of 2012. In the first three months of 2013, physical companies paid $212.4 million in congestion charges, an increase of $71.6 million or 50.2 percent compared to the first three months of 2012.

Table 10-34 Congestion cost by the type of the participant: January through March 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$29.4	$25.3	$30.0	$34.1	($12.4)	$1.2	($48.8)	($62.4)	$0.0	($28.3)
Physical	$55.6	($224.4)	$17.8	$297.7	$5.7	$72.0	($17.2)	($83.5)	$0.0	$214.2
Total	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9

Table 10-35 Congestion cost by the type of the participant: January through March 2012

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	($2.0)	($1.3)	$21.9	$21.2	($4.9)	$1.6	($35.0)	($41.4)	$0.0	($20.2)
Physical	$25.5	($128.6)	$5.6	$159.7	$0.5	$10.5	($7.0)	($17.0)	$0.0	$142.7
Total	$23.5	($129.9)	$27.5	$180.9	($4.3)	$12.1	($42.0)	($58.4)	$0.0	$122.4

26 The total zonal congestion numbers were calculated as of April 15, 2013 and are, based on continued PJM billing updates, subject to change.

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At March 31, 2013, 73,156 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 197,000 MW in the first three months of 2013. Wind projects account for approximately 19,079 MW of nameplate capacity, 26.1 percent of the MW in the queues, and combined-cycle projects account for 42,217 MW, 57.7 percent of the MW in the queues.

- **Generation Retirements.** As shown in Table 11-11, 11,844.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through March 31, 2013, and it is expected that a total of 20,297.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through March 31, 2013, account for 8,453.2 MW, or 39.6 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.2 percent of retirements during this period. Overall, 3,508.1 MW, or 29.6 percent of all MW planned for deactivation from 2013 through 2019, 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, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built, including 7,584.2 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key 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 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; and Susquehanna – Roseland.

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 transmission and generation to meet loads in an area. PJM has taken a first step towards

1 OATT Parts IV & VI.

integrating transmission investments into the market through the use of economic evaluation metrics.[2] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

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 March 31, 2013, 73,156 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 197,000 MW in 2013. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[3] Overall, 362 MW of nameplate capacity were added in PJM in the first three months of 2013.

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through the first three months of 2013[4]

	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
2012	2,669
2013	362

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 Y was active through March 31, 2013.

Capacity in generation request queues for the eight year period beginning in 2013 and ending in 2020 decreased by 3,231 MW from 76,387 MW in 2012 to

2 *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).

3 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.

4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

73,156 MW on March 31, 2013, or 4.2 percent (Table 11-2).[5] Queued capacity scheduled for service in 2013 decreased from 22,120 MW to 17,889 MW, or 19.1 percent. Queued capacity scheduled for service in 2014 decreased from 8,086 MW to 7,143 MW, or 5.6 percent. The 73,156 MW include generation with scheduled in-service dates in 2013 and units still active in the queue with in-service dates scheduled before 2013, listed at nameplate capacity, although these units are not yet in service.

Table 11-2 Queue comparison (MW): March 31, 2013 vs. December 31, 2012

	MW in the Queue 2012	MW in the Queue 2013	Year-to-Year Change (MW)	Year-to-Year Change
2013	22,120	17,889	(4,231)	(19.1%)
2014	8,086	7,143	(944)	(11.7%)
2015	22,295	21,052	(1,244)	(5.6%)
2016	11,788	13,397	1,609	13.7%
2017	8,932	10,165	1,233	13.8%
2018	3,165	3,165	0	0.0%
2019	0	0	0	NA
2020	0	346	346	NA
Total	76,387	73,156	(3,231)	(4.2%)

Table 11-3 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.[6]

Table 11-3 Capacity in PJM queues (MW): At March 31, 2013[7,8]

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	1,116	0	17,934	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	218	80	2,345	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	422	3,556	4,482
N Expired 31-Jan-05	0	2,399	38	8,090	10,527
O Expired 31-Jul-05	10	1,691	825	5,066	7,592
P Expired 31-Jan-06	393	3,065	253	4,928	8,638
Q Expired 31-Jul-06	120	2,248	2,694	9,472	14,534
R Expired 31-Jan-07	1,296	1,216	728	19,514	22,755
S Expired 31-Jul-07	1,778	3,243	370	11,751	17,142
T Expired 31-Jan-08	3,724	1,275	631	21,916	27,546
U Expired 31-Jan-09	3,114	733	132	29,378	33,357
V Expired 31-Jan-10	4,870	264	1,597	10,275	17,005
W Expired 31-Jan-11	8,055	322	1,709	14,160	24,245
X Expired 31-Jan-12	16,955	123	1,964	11,331	30,373
Y Through 31-Mar-13	21,254	5	146	1,537	22,941
Total	61,567	34,502	11,589	242,352	350,010

Data presented in Table 11-4 show that through the first three months of 2013, 36.9 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.3 percent was from Queues C, D and E.[9] As of March 31, 2013, 9.9 percent of all queued capacity has been placed in service, and 13.2 percent of all queued capacity is either complete or under construction.

The data presented in Table 11-4 show that for successful projects there is an average time of 840 days between entering a queue and the in-service date,

5 See the *2012 State of the Market Report for PJM*: Volume II, Section 11, pp. 318-323, for the queues in 2012.
6 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.

7 The *2013 Quarterly State of the Market Report for PJM: January through March* contains all projects in the queue including reratings of existing generating units and energy only resources.
8 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
9 The data for Queue Y include projects through March 31, 2013.

an increase of 9 days over the 2012 average. The data also show that for withdrawn projects, there is an average time of 577 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Average project queue times (days): At March 31, 2013

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	922	696	0	4,636
In-Service	840	718	0	3,964
Suspended	2,061	894	704	3,849
Under Construction	1,416	754	0	4,370
Withdrawn	564	577	0	4,249

Table 11-5 shows active queued capacity that was planned to be in service by April 1, 2013. This indicates there is a substantial amount of queued capacity, 7,955.2 MW, that should already be in service based on the original queue date but that is not yet even under construction. The MMU recommends that a review process be created to ensure that projects are removed from the queue, if they are no longer viable and no longer planning to complete the project.

Table 11-5 Active capacity queued to be in service prior to April 1, 2013

	MW
2007	27.0
2008	190.0
2009	294.0
2010	1,199.8
2011	2,532.4
2012	3,471.4
2013	240.6
Total	7,955.2

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. At March 31, 2013, 73,156 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 197,000 MW in 2013. Wind projects account for 19,079 MW of nameplate capacity or 26.1 percent of the capacity in the queues and combined-cycle projects account for 42,792 MW of capacity or 58.5 percent of the capacity in the queues.[10] On March 31, 2013, there were 42,792 MW of capacity from combined cycle units in the queue, compared to 42,724 MW in 2012, an increase of 0.2 percent. At March 31, 2013, there was queued combined cycle capacity in nearly every zone in PJM, and after accounting for the derating of wind and solar resources, combined cycle capacity comprises 77.5 percent of the MW in the queue able to offer into RPM auctions.

Table 11-6 shows the projects under construction or active as of March 31, 2013, by unit type and control zone. Most of the steam projects (99.4 percent of the MW) and most of the wind projects (92.6 percent of the MW) are outside the Eastern MAAC (EMAAC)[11] and Southwestern MAAC (SWMAAC)[12] locational deliverability areas (LDAs).[13] Of the total capacity additions, only 16,142 MW, or 22.1 percent, are projected to be in EMAAC, while 4,225 MW or 5.7 percent are projected to be constructed in SWMAAC. Of total capacity additions, 29,392 MW, or 40.1 percent of capacity, is being added inside MAAC zones. Overall, 72.2 percent of capacity is being added outside EMAAC and SWMAAC, and 59.8 percent of capacity is being added outside MAAC zones, not accounting for the planned integration of the EKPC zone in 2013. Wind projects account for 2,602 MW of capacity in MAAC LDAs, or 8.9 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,407 MW of capacity, or 8.7 percent.

10 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 19,079 MW of wind resources and 2,154 MW of solar resources, the 73,156 MW currently active in the queue would be reduced to 55,222 MW.

11 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

12 SWMAAC consists of the BGE and Pepco Control Zones.

13 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At March 31, 2013

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	3,495	71	9	0	0	495	0	0	1,069	5,138
AEP	5,074	40	20	70	0	44	2,124	84	8,894	16,350
AP	2,048	0	33	75	0	143	341	0	547	3,186
ATSI	4,633	40	6	0	30	15	135	0	849	5,708
BGE	678	256	4	0	0	22	0	0	0	960
ComEd	1,530	361	52	23	473	64	0	42	4,837	7,381
DAY	0	0	2	112	0	23	12	12	845	1,006
DEOK	20	0	0	0	0	0	0	0	0	20
DLCO	40	0	0	0	91	0	460	0	0	591
Dominion	6,501	535	11	0	1,594	65	312	0	505	9,522
DPL	1,223	2	0	0	0	238	22	0	318	1,802
JCPL	2,550	0	30	0	0	802	0	0	0	3,382
Met-Ed	1,818	0	21	0	58	3	0	0	0	1,900
PECO	874	7	4	0	330	10	0	5	0	1,229
PENELEC	879	43	37	0	0	32	96	0	738	1,825
Pepco	3,245	0	20	0	0	0	0	0	0	3,265
PPL	4,683	0	8	3	100	29	0	20	458	5,301
PSEG	3,952	390	9	0	50	170	0	0	20	4,591
Total	43,241	1,744	266	283	2,726	2,154	3,501	162	19,079	73,156

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)

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2013[14]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	12,093	469	52	0	380	1,715	22	5	1,407	16,142
SWMAAC	3,923	256	24	0	0	22	0	0	0	4,225
WMAAC	7,380	43	66	3	158	64	96	20	1,195	9,025
Non-MAAC	19,396	1,425	124	280	2,188	353	3,383	138	16,477	43,765
Total	42,792	2,193	266	283	2,726	2,154	3,501	162	19,079	73,156

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. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones.

14 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 11-8 Existing PJM capacity: At March 31, 2013[15] (By zone and unit type (MW))

	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	21	0	0	0	40	1,087	0	8	2,025
AEP	4,900	3,682	63	0	1,072	2,071	0	21,527	0	1,753	35,068
AP	1,129	1,215	48	0	80	0	36	7,358	27	999	10,892
ATSI	685	1,661	74	0	0	2,134	0	6,540	0	0	11,094
BGE	0	835	11	0	0	1,716	0	3,007	0	0	5,569
ComEd	1,770	7,244	98	0	0	10,438	0	5,417	5	2,454	27,426
DAY	0	1,369	48	0	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	0	2,646	0	0	3,488
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	174	0	3,589	3,581	3	8,356	0	0	23,494
DPL	1,125	1,820	96	30	0	0	4	1,800	0	0	4,876
External	974	990	0	0	66	439	0	6,238	0	185	8,892
JCPL	1,693	1,233	27	0	400	615	42	15	0	0	4,024
Met-Ed	2,051	408	41	0	20	805	0	844	0	0	4,168
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	344	46	0	513	0	0	6,831	0	931	8,663
Pepco	230	1,092	12	0	0	0	0	3,649	0	0	4,983
PPL	1,808	617	49	0	582	2,520	15	5,537	0	220	11,346
PSEG	3,091	2,838	12	0	5	3,493	105	2,050	2	0	11,597
Total	27,102	31,506	821	30	7,974	34,135	249	89,032	35	6,549	197,434

Table 11-9 shows the age of PJM generators by unit type.

Table 11-9 PJM capacity (MW) by age: at March 31, 2013

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,997	9,274	470	30	11	0	249	2,497	35	6,515	38,077
11 to 20	6,069	13,041	106	0	48	0	0	3,261	0	34	22,560
21 to 30	1,594	1,663	56	0	3,448	15,409	0	8,502	0	0	30,672
31 to 40	244	3,108	43	0	105	16,361	0	29,222	0	0	49,083
41 to 50	198	4,420	132	0	2,915	2,365	0	29,359	0	0	39,389
51 to 60	0	0	15	0	379	0	0	13,516	0	0	13,910
61 to 70	0	0	0	0	0	0	0	2,526	0	0	2,526
71 to 80	0	0	0	0	280	0	0	95	0	0	375
81 to 90	0	0	0	0	549	0	0	54	0	0	603
91 to 100	0	0	0	0	155	0	0	0	0	0	155
101 and over	0	0	0	0	84	0	0	0	0	0	84
Total	27,102	31,506	821	30	7,974	34,135	249	89,032	35	6,549	197,434

15 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

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 2020. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. New gas-fired capability would represent 90.8 percent of all new capacity in EMAAC when the derating of wind and solar capacity is reflected.

In 2012, a planned addition of 1,640 MW of nuclear capacity to Calvert Cliffs in SWMAAC was withdrawn from the queue. Without the planned nuclear capability in SWMAAC, new gas-fired capability represents 98.9 percent of all new capability in the SWMAAC. In 2020, this would mean that CC and CT generators would comprise 55.0 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.[16] In these zones, 87.8 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2020, wind farms would comprise 15.8 percent of total MW ICAP in Non-MAAC zones, if all queued MW are built.

16 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion Control Zones.

Table 11-10 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2020[17]

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 2020	Estimated Capacity 2020	Percent of Area Total
EMAAC	Combined Cycle	198	2.4%	9,282	27.5%	12,093	21,177	50.0%
	Combustion Turbine	2,229	27.5%	7,433	22.0%	469	5,674	13.4%
	Diesel	48	0.6%	159	0.5%	52	163	0.4%
	Fuel Cell	0	0.0%	30	1.6%	0	30	1.8%
	Hydroelectric	2,042	25.2%	2,047	6.1%	0	620	1.5%
	Nuclear	615	7.6%	8,654	25.6%	380	8,420	19.9%
	Solar	0	0.0%	194	0.6%	1,715	1,909	4.5%
	Steam	2,981	36.7%	5,931	17.6%	22	2,972	7.0%
	Storage	0	0.0%	3	0.0%	5	8	0.0%
	Wind	0	0.0%	8	0.0%	1,407	1,415	3.3%
	EMAAC Total	8,112	100.0%	33,741	100.0%	16,142	42,385	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,923	4,153	39.4%
	Combustion Turbine	542	12.8%	1,927	18.3%	256	1,640	15.6%
	Diesel	0	0.0%	23	0.2%	24	47	0.4%
	Nuclear	0	0.0%	1,716	16.3%	0	1,716	16.3%
	Solar	0	0.0%	0	0.0%	22	22	0.2%
	Steam	3,702	87.2%	6,656	63.1%	0	2,954	28.0%
	SWMAAC Total	4,244	100.0%	10,552	100.0%	4,225	10,533	100.0%
WMAAC	Combined Cycle	0	0.0%	3,859	16.0%	7,380	11,239	45.1%
	Combustion Turbine	558	6.1%	1,368	5.7%	43	854	3.4%
	Diesel	46	0.5%	136	0.6%	66	156	0.6%
	Hydroelectric	887	9.7%	1,114	4.6%	3	1,117	4.5%
	Nuclear	0	0.0%	3,325	13.8%	158	3,483	14.0%
	Solar	0	0.0%	15	0.1%	64	79	0.3%
	Steam	7,702	83.8%	13,211	54.6%	96	5,606	22.5%
	Storage	0	0.0%	0	0.0%	20	20	0.1%
	Wind	0	0.0%	1,151	4.8%	1,195	2,346	9.4%
	WMAAC Total	9,193	100.0%	24,178	100.0%	9,025	24,898	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,732	10.6%	19,396	33,128	23.9%
	Combustion Turbine	1,092	3.1%	20,779	16.1%	1,425	21,112	15.2%
	Diesel	53	0.1%	504	0.4%	124	576	0.4%
	Hydroelectric	1,433	4.0%	4,814	3.7%	280	5,093	3.7%
	Nuclear	1,751	4.9%	20,440	15.8%	2,188	20,877	15.1%
	Solar	0	0.0%	40	0.0%	353	393	0.3%
	Steam	31,166	87.8%	63,233	49.0%	3,383	35,451	25.6%
	Storage	0	0.0%	32	0.0%	138	170	0.1%
	Wind	0	0.0%	5,391	4.2%	16,477	21,868	15.8%
	Non-MAAC Total	35,493	100.0%	128,964	100.0%	43,765	138,668	100.0%
All Areas	Total	57,042		197,434		73,156	216,484	

17 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.

Planned Deactivations

As shown in Table 11-11, 11,844.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through March 31, 2013, and it is expected that a total of 20,297.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through March 31, 2013, account for 8,453.2 MW, or 39.6 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.2 percent of retirements during this period. Overall, 3,508.1 MW, or 29.6 percent of all MW planned for deactivation from 2013 through 2019, are expected in the AEP zone. Since January 1, 2013, 1,340.5 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating.

Table 11-11 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,322.3
Retirements 2012	6,961.9
Retirements 2013	169.0
Planned Retirements 2013	237.4
Planned Retirements Post-2013	11,606.8
Total	20,297.4

Figure 11-1 Unit retirements in PJM: 2012 through 2019

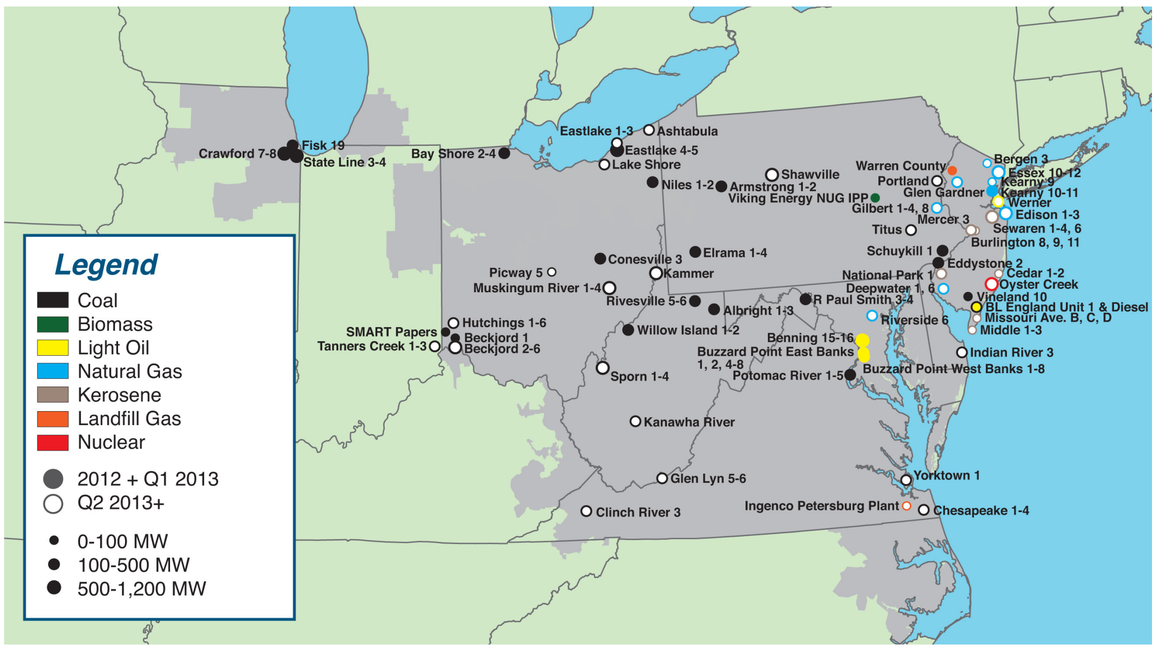


Table 11-12 Planned deactivations of PJM units, as of May 1, 2013

Unit	Zone	MW	Projected Deactivation Date
Warren County Landfill	JCPL	2.9	09-Jan-13
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
BL England 1	AECO	113.0	30-Apr-14
Riverside 6	BGE	115.0	01-Jun-14
Burlington 9	PSEG	184.0	01-Jun-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1-2	Dominion	323.0	31-Dec-14
Portland	Met-Ed	401.0	07-Jan-15
Beckjord 2-6	DEOK	1,024.0	01-Apr-15
Titus	Met-Ed	243.0	16-Apr-15
Shawville	PENELEC	597.0	16-Apr-15
Gilbert 1-4, 8	JCPL	188.0	01-May-15
Glen Gardner	JCPL	160.0	01-May-15
Werner 1-4	JCPL	212.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Middle 1-3	AECO	74.7	31-May-15
Missouri Ave B, C, D	AECO	60.0	31-May-15
Essex 12	PSEG	184.0	31-May-15
Clinch River 3	AEP	230.0	01-Jun-15
Glen Lyn 5-6	AEP	325.0	01-Jun-15
Kammer	AEP	600.0	01-Jun-15
Kanawha River	AEP	400.0	01-Jun-15
Muskingum River 1-4	AEP	790.0	01-Jun-15
Picway 5	AEP	95.0	01-Jun-15
Sporn	AEP	580.0	01-Jun-15
Tanners Creek 1-3	AEP	488.1	01-Jun-15
Ashtabula	ATSI	210.0	01-Jun-15
Eastlake 1-3	ATSI	327.0	01-Jun-15
Lake Shore	ATSI	190.0	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8, 11	PSEG	205.0	01-Jun-15
Edison 1-3	PSEG	504.0	01-Jun-15
Essex 10-11	PSEG	352.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 1-4, 6	PSEG	558.0	01-Jun-15
BL England Diesels	AECO	8.0	01-Oct-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		11,844.2	

Table 11-13 HEDD Units in PJM as of March 31, 2013[18]

Unit	Zone	MW	Deactivation Date
Carlls Corner 1-2	AECO	72.6	NA
Cedar Station 1-3	AECO	66.0	31-May-15
Cumberland 1	AECO	92.0	NA
Mickleton 1	AECO	72.0	NA
Middle Street 1-3	AECO	75.3	31-May-15
Missouri Ave. B,C,D	AECO	60.0	31-May-15
Sherman Ave.	AECO	92.0	NA
Vineland West CT	AECO	26.0	01-Sep-12
Forked River 1-2	JCPL	65.0	NA
Gilbert 4-7, 9, C1-C4	JCPL	446.0	01-May-15
Glen Gardner A1-A4, B1-B4	JCPL	160.0	01-May-15
Lakewood 1-2	JCPL	316.1	NA
Parlin NUG	JCPL	114.0	NA
Sayreville C1-C4	JCPL	224.0	NA
South River NUG	JCPL	299.0	NA
Werner C1-C4	JCPL	212.0	01-May-15
Bayonne	PSEG	118.5	NA
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0	01-Jun-15
Camden	PSEG	145.0	NA
Eagle Point 1-2	PSEG	127.1	NA
Edison 11-14, 21-24, 31-34	PSEG	504.0	01-Jun-15
Elmwood	PSEG	67.0	NA
Essex 101-104, 111-114, 121,124	PSEG	536.0	01-Jun-15
Kearny 9-11, 121-124	PSEG	446.0	01-May-15
Linden 1-2	PSEG	1,230.0	NA
Mercer 3	PSEG	115.0	01-Jun-15
National Park	PSEG	21.0	01-Jun-15
Newark Bay	PSEG	120.2	NA
Pedricktown	PSEG	120.3	NA
Salem 3	PSEG	38.4	NA
Sewaren 6	PSEG	105.0	01-Jun-15
Total		6,663.5	

18 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed April 1, 2013)

Actual Generation Deactivations in 2013

Table 11-14 shows unit deactivations for 2013 through March 31, 2013.[19] A total of 169.0 MW retired from January 1, 2013, through March 31, 2013.

Table 11-14 Unit deactivations: January 2013 through March 31, 2013

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13

Updates on Key Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the EHV (Extra High Voltage) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland.

The Mount Storm – Doubs transmission line, that serves West Virginia, Virginia and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life, and require replacement to ensure reliability in its service areas. "As of April, 2013, construction is proceeding ahead of schedule. All structure foundations are complete, approximately 70 percent of the structures have been erected, and more than 70 percent of the line is complete."[20]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh – Juniata and Keystone – Juniata 500kV circuits. The plans are for construction of the foundation in late 2013, construction in 2014 and completion in early 2015.

The Susquehanna – Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna – Roseland will be a new 500 kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. On October 1, 2012, the Susquehanna – Roseland project received final approval from the National Park Service (NPS) for the project to be constructed on the route selected by PSEG and PPL.[21] The Susquehanna – Hopatcong portion of the project is currently expected to be in-service by June, 2014, with the remainder of the project to be completed by June, 2015.

19 "*PJM Generator Deactivations*," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 24, 2013).
20 "*Mt. Storm – Doubs 500kV Rebuild Project*," Dom.com <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (May 7, 2013).
21 See PSEG.com. "Susquehanna-Roseland line receives final federal approval," <http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp> (Accessed November 1, 2012).

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 (FTRs) 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.[2,3]

The *2013 Quarterly State of the Market Report for PJM: January through March,* focuses on the Monthly Balance of Planning Period FTR Auctions during the 2012 to 2013 planning period, which covers June 1, 2012, through March 31, 2013.

Table 12-1 The FTR Auction Markets results were competitive

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

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259-62,260 & n. 123.
3 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."

- 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.
- 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 mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2012 through March 2013) of the 2012 to 2013 planning period, total participant FTR sell offers were 4,627,336 MW, down from 5,330,537 MW for the same period during the 2011 to 2012 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 (June 2012 through March 2013) planning period increased 11.8 percent from 16,367,977 MW for the same time period of the prior planning period, to 18,299,865 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.0 percent of prevailing flow and 87.9 percent of counter flow FTRs for 2013. Financial entities owned 65.0 percent of all prevailing and counter flow FTRs, including 56.3 percent of

all prevailing flow FTRs and 81.5 percent of all counter flow FTRs during the same time period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first nine months of the 2012 to 2013 planning period were $492,556 (0.06 percent of total FTR target allocations).
- **Credit Issues.** Four participants defaulted during 2013 from eight default events. The average of these defaults was $68,812 with four based on inadequate collateral and four based on nonpayment. The average collateral default was $13,275 and the average nonpayment default was $124,349. The majority of these defaults were promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first ten months of the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,976,401 MW (10.8 percent) of FTR buy bids and 651,226 MW (14.1 percent) of FTR sell offers.
- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 planning period was $0.12, up from $0.10 per MW in the first ten months of the 2011 to 2012 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $21.7 million in net revenue for all FTRs for the first ten months of the 2012 to 2013 planning period, down from $24.8 million for the same time period in the 2011 to 2012 planning period.
- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the 2011 to 2012 planning period.[4] FTRs were paid at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $533.2 million of FTR revenues during the first ten months of the 2012 to 2013 planning period and $799.4 million during the 2011 to 2012 planning period. For the first ten months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were PSEG and Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both Western Hub.
- **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 $67.4 million in profits for physical entities, of which $63.6 million was from self-scheduled FTRs, and $45.1 million for financial entities. As shown in Table 12-9, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the 2012 to 2013 planning period PJM allocated a total of 14,211.2 MW of residual ARRs with a total target allocation of $4,475,521.
- **ARR Reassignment for Retail Load Switching.** There were 48,077 MW of ARRs associated with approximately $464,100 of revenue that were reassigned in the first ten months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900

4 Unless specifically noted, payout ratios reported in this section are calculated using PJM's method and are consistent with PJM's reported payout ratios.

of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Revenue Adequacy.** For the first ten months of the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $624.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through March 31, 2013, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **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 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 89.8 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

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 and FTR holders do not have the right to revenue adequacy.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. FTR holders appropriately receive revenues based on actual congestion in both day ahead and real time markets. When day ahead congestion differs significantly from real time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with the differences between modeling in the day ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The payout ratio reported by PJM is understated. The reported payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs. For the 2012 to 2013 planning period, the reported payout ratio is 69.5 percent while the correctly calculated payout ratio is 72.2 percent. The MMU recommends that the calculation of the FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the first ten months of the 2012 to 2013 planning period would have been 85.2 percent instead of the reported 69.5 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the first ten months of the 2012 to 2013 planning period from the reported 69.5 percent to 89.1 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day ahead and balancing congestion. These reasons include the inadequate transmission outage modeling which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day ahead and real time markets, including reactive interfaces; differences in day ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

Financial Transmission Rights

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, subject to revenue availability. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[5] 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 on individual FTR paths are used to fund FTRs on paths which received less than their target allocations.

FTR funding is not on a path specific basis or on a time specific basis. There are cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue. FTR auction revenues and excess revenues are 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

5 For additional information on marginal losses, see the *2012 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

charge is collected from any FTR market participants that hold FTRs for 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.

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 types of FTR 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.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow 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.

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.

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.[6] 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

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 38.

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.[7] 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 significant distributional consequences.

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. Existing FTRs are modeled as fixed injections and withdraws. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. 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.[8]

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

The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2012 to 2013 planning period decreased 3.5 percent to 1,976,401 MW.

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 the secondary bilateral market.

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 12-2 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through March 2013 by trade type, organization type and FTR direction. Financial entities purchased 83.0 percent of prevailing flow and 87.9 percent of counter flow FTRs for the first ten months of the 2012 to 2013 planning period, with the result that financial entities purchased

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 54.
8 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 39.

65.0 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through March 2013.

Table 12-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through March 2013

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	17.0%	12.1%	15.1%
	Financial	83.0%	87.9%	84.9%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	18.8%	19.5%	19.0%
	Financial	81.2%	80.5%	81.0%
	Total	100.0%	100.0%	100.0%

Table 12-3 presents the daily FTR net position ownership for January through March 2013, by FTR direction.

Table 12-3 Daily FTR net position ownership by FTR direction: January through March 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	43.7%	18.5%	35.0%
Financial	56.3%	81.5%	65.0%
Total	100.0%	100.0%	100.0%

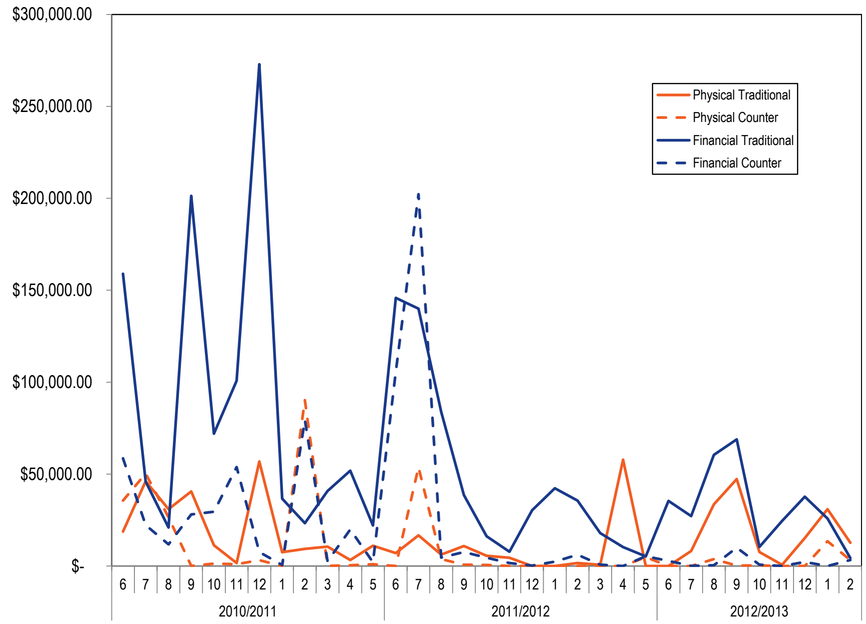
Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the Day-ahead congestion LMP difference is greater than the real time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 12-1 shows the FTR forfeitures values for both counter flow and prevailing flow FTRs for each month of June 2010 through February 2013 by company type.[9] Total forfeitures for the first ten months of the 2012 to 2013 planning period were $492,556 (0.06 percent of total FTR target allocations).

Figure 12-1 Monthly FTR Forfeitures for physical and financial participants: June 2010 through February 2013



9 March forfeitures are not billed to customers until after the issuance of this report.

Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

Four participants defaulted during 2013 from eight default events. The average of these defaults was $68,812 with four based on inadequate collateral and four based on nonpayment. The average collateral default was $13,275 and the average nonpayment default was $124,349. The majority of these defaults were promptly cured.

Market Performance

Volume

Table 12-4 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2011 to 2012 planning period and the first ten months of the 2012 to 2013 planning period. There were 11,652,143 MW of FTR buy bid obligations and 3,621,897 MW of FTR sell offer obligations for all bidding periods in the 2012 to 2013 planning period through March 31, 2013. The monthly balance of planning period auctions cleared 1,908,482 MW (16.4 percent) of FTR buy bid obligations and 415,307 MW (11.5 percent) of FTR sell off obligations.

There were 6,647,722 MW of FTR buy bid options and 1,005,439 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period through March 31, 2013. The monthly auctions cleared 67,918 MW (1.0 percent) of FTR buy bid options, and 235,919 MW (23.5 percent) of FTR sell offers.

Table 12-4 Monthly Balance of Planning Period FTR Auction market volume: January through March 2013

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-13	Obligations	Buy bids	150,397	963,036	166,622	17.3%	796,414	82.7%
		Sell offers	84,563	297,609	34,710	11.7%	262,899	88.3%
	Options	Buy bids	2,830	104,318	6,767	6.5%	97,551	93.5%
		Sell offers	10,204	73,624	17,322	23.5%	56,302	76.5%
Feb-13	Obligations	Buy bids	164,620	1,035,756	166,386	16.1%	869,369	83.9%
		Sell offers	76,210	261,631	36,402	13.9%	225,229	86.1%
	Options	Buy bids	2,518	94,039	4,749	5.0%	89,290	95.0%
		Sell offers	9,053	62,833	16,434	26.2%	46,399	73.8%
Mar-13	Obligations	Buy bids	168,718	1,092,986	188,849	17.3%	904,138	82.7%
		Sell offers	77,248	256,820	40,079	15.6%	216,741	84.4%
	Options	Buy bids	2,674	103,046	5,591	5.4%	97,455	94.6%
		Sell offers	10,054	84,993	21,581	25.4%	63,411	74.6%
2011/2012*	Obligations	Buy bids	2,787,546	15,084,909	2,216,646	14.7%	12,868,263	85.3%
		Sell offers	1,078,612	5,164,979	551,669	10.7%	4,613,310	89.3%
	Options	Buy bids	40,237	2,549,347	58,829	2.3%	2,490,519	97.7%
		Sell offers	99,695	687,656	164,180	23.9%	523,476	76.1%
2012/2013**	Obligations	Buy bids	2,024,470	11,652,143	1,908,482	16.4%	9,743,660	83.6%
		Sell offers	1,000,008	3,621,897	415,307	11.5%	3,206,590	88.5%
	Options	Buy bids	101,282	6,647,722	67,918	1.0%	6,579,804	99.0%
		Sell offers	140,623	1,005,439	235,919	23.5%	769,519	76.5%

* Shows Twelve Months for 2011/2012; ** Shows ten months ended 31-Mar-13 for 2012/2013

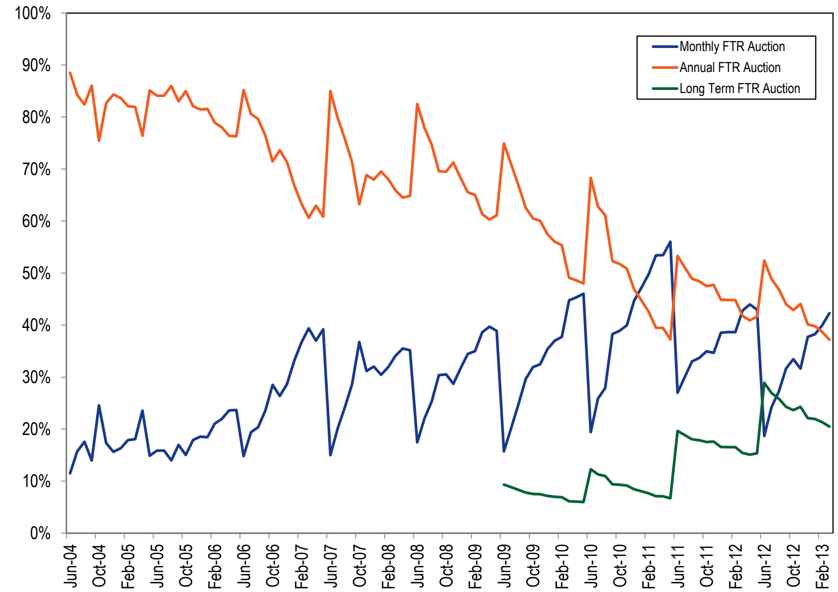
Table 12-5 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume.

Table 12-5 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through March 2013

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	Bid	595,260	191,417	115,207				165,471	1,067,354
	Cleared	125,075	24,018	8,251				16,045	173,389
Feb-13	Bid	654,446	174,360	177,548				123,440	1,129,794
	Cleared	131,562	15,659	13,975				9,939	171,135
Mar-13	Bid	645,247	232,876	224,105				93,804	1,196,032
	Cleared	136,007	27,219	24,669				6,544	194,440

Figure 12-2 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2013, by type of auction.[10] FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 12-2 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2013



10 Figure 12-2 does not include volume from FTRs directly allocated to either DEOK or ATSI zones as part of their integration for the 2011 to 2012 or 2012 to 2013 planning periods.

Table 12-6 provides the secondary bilateral FTR market volume for the entire 2011 to 2012 planning period and the ten months of the 2012 to 2013 planning period.

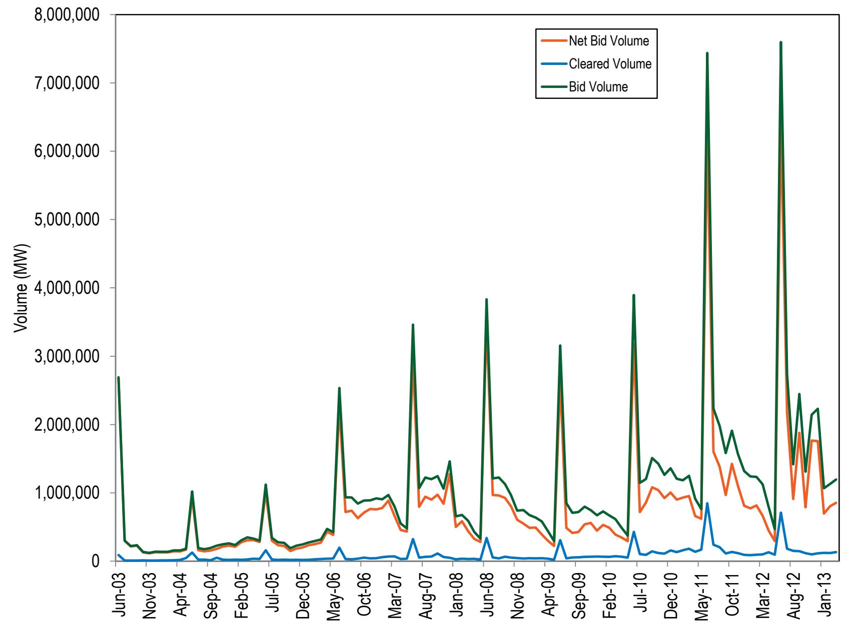
Table 12-6 Secondary bilateral FTR market volume: Planning periods 2011 to 2012 and 2012 to 2013[11]

Planning Period	Hedge Type	Class Type	Volume (MW)
2011/2012	Obligation	24-Hour	239
		On Peak	11,925
		Off Peak	4,268
		Total	16,431
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296
2012/2013*	Obligation	24-Hour	90
		On Peak	127
		Off Peak	40
		Total	257
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

* Shows ten months ended 31-Mar-2013

Figure 12-3 shows the FTR bid, cleared and net bid volume from June 2003 through March 2013 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

Figure 12-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through March 2013



Price

Table 12-7 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2013 through March 2013. For example, for the January 2013 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 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 ten months of the 2012 to 2013 planning

11 The 2012 to 2013 planning period covers bilateral FTRs that are effective for any time between June 1, 2012 through March 31, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

period was $0.12 per MW compared to $0.10 per MW for the same time frame in the 2011 to 2012 planning period.

Table 12-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through March 2013

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	$0.11	$0.19	$0.05				$0.09	$0.11
Feb-13	$0.08	$0.12	$0.10				$0.13	$0.09
Mar-13	$0.10	$0.12	$0.10				$0.05	$0.10

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 actual revenue that an FTR holder receives 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 12-8 lists FTR profits by organization type and FTR direction for the period from January through March, 2013. 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 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. FTRs were profitable overall, with $67.4 million in profits for physical entities, of which $63.6 million was from self-scheduled FTRs, and $45.1 million for financial entities.

Table 12-8 FTR profits by organization type and FTR direction: January through March 2013

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($4,671,333)	$62,599,515	$8,446,774	$1,033,054	$67,408,009
Financial	$17,887,161	NA	$27,202,962	NA	$45,090,122
Total	$13,215,828	$62,599,515	$35,649,736	$1,033,054	$112,498,132

Table 12-9 lists the monthly FTR profits in 2013 by organization type.

Table 12-9 Monthly FTR profits by organization type: January through March 2013

	Organization Type			
Month	Physical	Self Scheduled FTRs	Financial	Total
Jan	$1,219,347.95	$26,828,073.08	$18,582,903.58	$46,630,324.60
Feb	$12,412,193.25	$21,240,230.26	$20,507,943.83	$54,160,367.33
Mar	($9,856,100.25)	$15,564,264.86	$5,999,274.99	$11,707,439.60
Total	$3,775,440.94	$63,632,568.20	$45,090,122.40	$112,498,131.54

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 12-10 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through March 2013. The Monthly Balance of Planning Period FTR Auction netted $21.7 million in revenue, with buyers paying $117.6 million and sellers receiving $95.9 million. For the entire 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions netted $26.3 million in revenue with buyers paying $132.6 million and sellers receiving $106.4 million.

Table 12-10 Monthly Balance of Planning Period FTR Auction revenue: January through March 2013

Monthly Auction	Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-13	Obligations	Buy bids	$42,552	$4,558,023	$3,371,362	$7,971,937
		Sell offers	$106,975	$2,609,123	$1,599,772	$4,315,870
	Options	Buy bids	$0	$237,321	$153,334	$390,655
		Sell offers	$0	$1,133,641	$1,206,317	$2,339,958
Feb-13	Obligations	Buy bids	$176,565	$3,587,647	$2,468,155	$6,232,366
		Sell offers	$401,600	$1,782,016	$1,097,066	$3,280,682
	Options	Buy bids	$5,100	$99,651	$128,731	$233,482
		Sell offers	$0	$861,109	$904,603	$1,765,712
Mar-13	Obligations	Buy bids	$189,939	$4,040,854	$3,035,268	$7,266,060
		Sell offers	$61,862	$2,221,264	$1,434,875	$3,718,001
	Options	Buy bids	$16,526	$229,272	$95,137	$340,935
		Sell offers	$0	$1,242,062	$1,381,010	$2,623,072
2011/2012*	Obligations	Buy bids	$11,022,879	$70,675,860	$43,198,742	$124,897,481
		Sell offers	$4,694,451	$44,380,545	$26,582,133	$75,657,129
	Options	Buy bids	$117,492	$4,428,304	$3,191,765	$7,737,562
		Sell offers	$14,172	$18,614,021	$12,092,649	$30,720,842
	Total		$6,431,748	$12,109,598	$7,715,726	$26,257,072
2012/2013**	Obligations	Buy bids	$72,326	$70,463,354	$40,182,381	$110,718,061
		Sell offers	$4,106,051	$37,289,815	$17,371,988	$58,767,854
	Options	Buy bids	$105,393	$4,129,127	$2,644,932	$6,879,452
		Sell offers	$313,319	$20,684,343	$16,138,588	$37,136,250
	Total		$7,287,487	$92,019,131	$56,390,560	$155,697,178

* Shows Twelve Months; ** Shows ten months ended 31-Mar-2013 for 2012/2013

Figure 12-4 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 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $45.0 million of the total revenue of $21.7 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 sinks accounted for -$14.6 million of revenue and constituted 0.1 percent of all FTRs bought in the auction.

Figure 12-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: first ten months of the 2012 to 2013 planning period

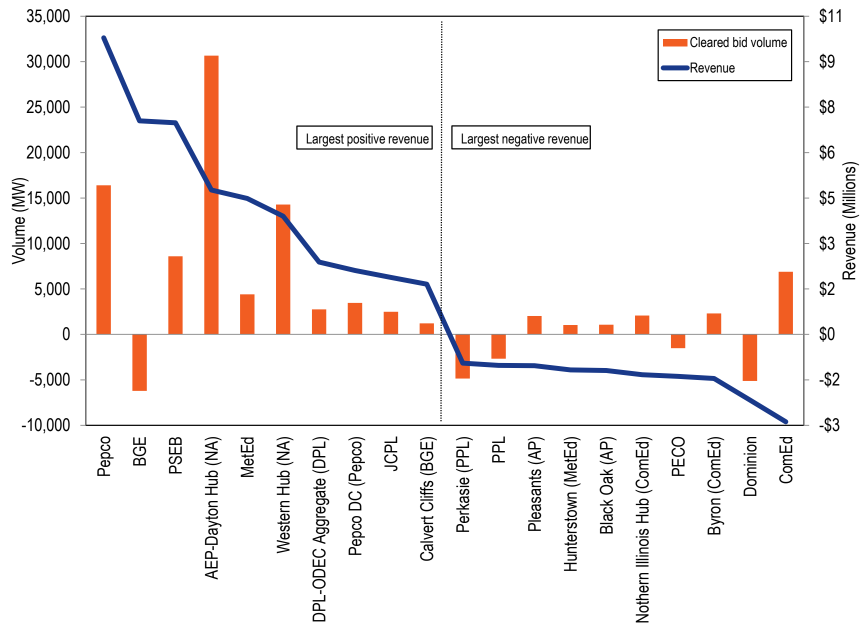
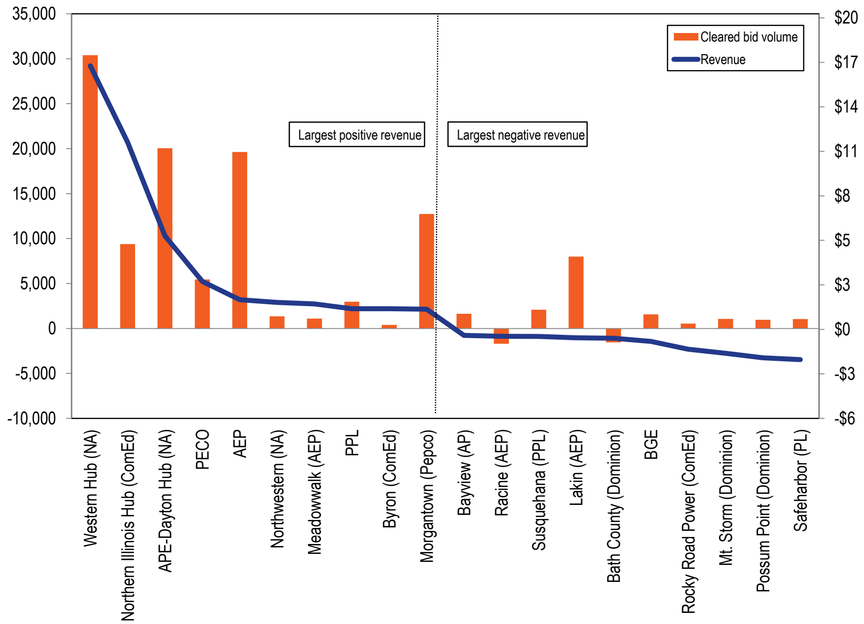


Figure 12-5 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $44.5 million of the total revenue of $21.7 million paid in the auction, they also comprised 7.8 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$12.6 million of revenue and constituted 1.0 percent of all FTRs bought in the auction.

Figure 12-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: first ten months of the 2012 to 2013 planning period



FTR Target Allocations

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 2012 to 2013 planning period through March 31, 2013. Figure 12-6 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2012 to 2013 planning period. The top 10 sinks that produced financial benefit accounted for 23.5 percent of total positive target allocations during the first ten months of the 2012 to 2013 planning period with the PSEG zone accounting for 4.3 percent of all positive target allocations. The top 10 sinks that created liability accounted for 8.8 percent of total negative target allocations with the Western Hub accounting for 2.0 percent of all negative target allocations.

Figure 12-6 Ten largest positive and negative FTR target allocations summed by sink: first ten months of the 2012 to 2013 planning period

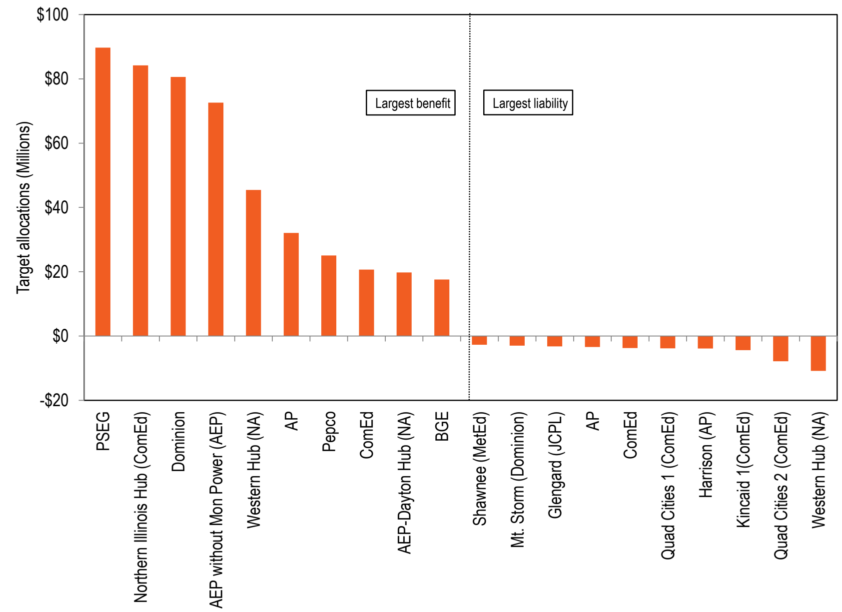
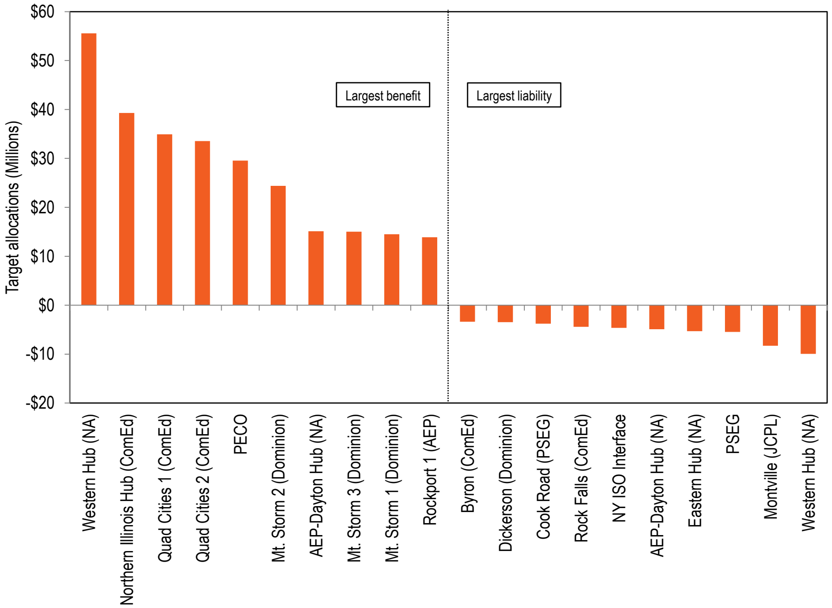


Figure 12-7 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2012 to 2013 planning period. The top 10 sources with a positive target allocation accounted for 13.3 percent of total positive target allocations with the Western Hub accounting for 2.7 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 10.0 percent of all negative target allocations, with the Western Hub accounting for 1.9 percent.

Figure 12-7 Ten largest positive and negative FTR target allocations summed by source: first ten months of the 2012 to 2013 planning period



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.[12] That is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. 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.

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 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day ahead and balancing markets, and net negative congestion.[13] 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

12 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."

13 Hourly congestion revenues may be negative.

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 12-11 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.[14] 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 payment of $0.2 million in congestion charges to Con Edison in the 2011 to 2012 planning period.[15,16]

Congestion charges were made to the Day Ahead Operating Reserves in October 2012, January 2013, and March 2013, for $0.6 million, $5.0 million and $0.7 million. These charges are necessary if the hourly congestion revenues are negative at the end of the month. If this happens, charges are allocated retroactively 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 and three times in the 2012 to 2013 planning period.

FTRs were paid at 69.5 percent of the target allocation level for the first ten months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $528.7 million of FTR revenues during the first ten months of the 2012 to 2013 planning period, and $705.9 million during the first ten months of the 2011 to 2012 planning period, a 25.1 percent decrease. For the first ten months of the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were PSEG and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

Table 12-11 presents the PJM FTR revenue detail for the 2011 to 2012 planning period and the first ten months of the 2012 to 2013 planning period.

Table 12-11 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013 through March 31, 2013

Accounting Element	2011/2012	2012/2013**
ARR information		
ARR target allocations	$982.9	$488.6
FTR auction revenue	$1,091.8	$542.8
ARR excess	$108.9	$54.3
FTR targets		
FTR target allocations	$992.8	$768.7
Adjustments:		
Adjustments to FTR target allocations	($1.1)	($0.6)
Total FTR targets	$991.7	$768.1
FTR revenues		
ARR excess	$108.9	$54.3
Competing uses	$0.1	$0.1
Congestion		
Net Negative Congestion (enter as negative)	($64.5)	($75.2)
Hourly congestion revenue	$835.5	$585.5
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($79.6)	($36.0)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.2)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.8)	($0.0)
Total FTR revenues	$799.4	$527.4
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$5.3
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	$799.4	$533.2
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$799.6	$533.2
Remaining deficiency	$192.3	$234.9

** Shows ten months ended 31-Mar-13

14 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)
15 111 FERC ¶ 61,228 (2005).
16 See the *2012 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 E-2, "Con Edison and PSE&G wheel settlements data: 2012."

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 12-12 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 12-12 is not the 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.

Table 12-12 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013

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-12	$58.5	$62.9	92.9%	$58.5	92.9%	($4.5)
Jul-12	$71.3	$80.1	88.9%	$71.3	88.9%	($8.9)
Aug-12	$54.1	$55.6	97.1%	$54.1	97.3%	($1.5)
Sep-12	$38.7	$82.8	46.7%	$38.7	46.8%	($44.1)
Oct-12	$24.3	$58.2	41.8%	$24.9	42.7%	($33.3)
Nov-12	$52.0	$59.7	87.2%	$52.0	87.3%	($7.7)
Dec-12	$36.3	$50.3	72.2%	$36.3	72.5%	($14.0)
Jan-13	$63.4	$120.4	53.4%	$68.0	56.5%	($52.4)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.3)
Summary for Planning Period 2012 to 2013						
Total	$527.4	$768.9		$533.3	69.4%	($235.5)

Figure 12-8 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through March 2013. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-8 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 2012 to 2013 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 12-8 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 through March 2013

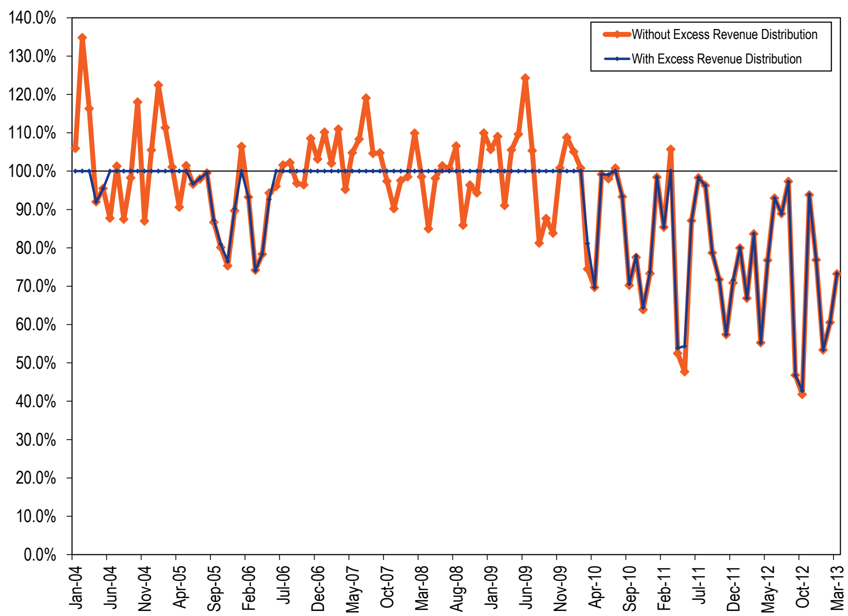


Table 12-13 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward.

Table 12-13 Reported 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	80.6%
2012/2013*	69.5%

*2012/2013 Through 31-Mar-13

Revenue Adequacy Issues and Solutions

Reported Payout Ratio

The payout ratios shown above in Table 12-13 reflect the reported payout ratios for the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour. But this does not correctly measure the payout ratio actually received by positive target allocation FTR holders. The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in an hour. In fact, the actual payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour are included with congestion revenue when funding FTRs with net positive target allocations.[17] The actual payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs is greater than reported by PJM.

17 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012), p. 50

Table 12-14 shows the reported and actual payout ratio for the first ten months of the 2012 to 2013 planning period. In September the reported payout ratio is 8.8 percentage points below the actual payout ratio. For the planning period, the reported payout ratio is 2.8 percentage points below the actual payout ratio. For the first ten months of the 2012 to 2013 planning period, the reported payout ratio is 69.5 percent while the correctly calculated payout ratio is 72.3 percent.

Table 12-14 Reported and Actual Payout Ratios: June 2012 through March 2013

	Reported Payout Ratio	Actual Payout Ratio
Jun-12	93.0%	93.6%
Jul-12	89.0%	90.1%
Aug-12	97.5%	97.7%
Sep-12	47.0%	55.8%
Oct-12	42.7%	50.9%
Nov-12	87.3%	88.5%
Dec-12	72.3%	74.6%
Jan-13	56.8%	59.7%
Feb-13	60.2%	62.5%
Mar-13	74.2%	75.5%
Total	69.5%	72.3%

Netting Target Allocations within Portfolios

Currently FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Table 12-15 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net TA is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 12-15 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive TA	Negative TA	Percent Negative TA	Net TA	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 12-16 shows the total value for the first ten months of the 2012 to 2013 planning period of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio so far for the 2012 to 2013 planning period would have been 85.2 percent instead of the reported 69.5 percent.

Table 12-16 Monthly positive and negative target allocations and payout ratios with and without hourly netting for the 2012 to 2013 planning period

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jun-12	$69,557,299	($6,623,560)	$121,217,938	($58,280,956)	$58,463,402	92.9%	96.3%
Jul-12	$89,179,225	($9,034,200)	$173,602,611	($93,421,963)	$71,254,665	88.9%	94.9%
Aug-12	$60,694,118	($5,115,960)	$111,642,193	($55,976,928)	$54,064,320	97.3%	98.6%
Sep-12	$99,154,010	($16,477,176)	$179,647,915	($96,844,326)	$38,699,241	46.8%	75.4%
Oct-12	$68,051,707	($9,827,426)	$137,698,279	($79,454,756)	$24,821,559	42.6%	75.7%
Nov-12	$66,233,739	($6,557,217)	$124,142,020	($64,424,379)	$52,049,442	87.2%	93.8%
Dec-12	$54,866,078	($4,610,245)	$110,328,974	($59,848,711)	$36,289,881	72.2%	87.1%
Jan-13	$129,096,732	($8,682,957)	$233,783,161	($113,347,680)	$68,350,654	56.8%	77.7%
Feb-13	$135,713,011	($7,613,077)	$259,657,461	($131,557,526)	$77,154,565	60.2%	80.4%
Mar-13	$74,434,140	($3,760,700)	$146,552,085	($75,878,638)	$52,429,117	74.2%	87.6%
Total	$846,980,059	($78,302,518)	$1,598,272,637	($829,035,863)	$533,576,848	69.4%	85.3%

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 12-17 shows the monthly positive, negative and total target allocations.[18] Table 12-17 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $61.7 million in revenue available to fund positive target allocations.

18 Reported payout ratio may differ between Table 12-16 and Table 12-17 due to rounding differences when netting target allocations and considering each FTR individually.

Table 12-17 Counter flow FTR payout ratio adjustment impacts

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jun-12	$121,217,938	($58,280,956)	$62,936,981	$58,463,402	92.9%	$116,744,359	97.1%	$117,660,567
Jul-12	$173,602,611	($93,421,963)	$80,180,649	$71,254,665	88.9%	$164,676,628	96.1%	$166,755,703
Aug-12	$111,642,193	($55,976,928)	$55,665,265	$54,064,320	97.1%	$110,041,248	98.9%	$110,403,489
Sep-12	$179,647,915	($96,844,326)	$82,803,589	$38,699,241	46.7%	$135,543,567	82.3%	$147,775,239
Oct-12	$137,698,279	($79,454,756)	$58,243,523	$24,821,559	42.6%	$104,276,315	82.8%	$113,967,134
Nov-12	$124,142,020	($64,424,379)	$59,717,640	$52,049,442	87.2%	$116,473,822	95.3%	$118,341,423
Dec-12	$110,328,974	($59,848,711)	$50,480,263	$36,289,881	71.9%	$96,138,591	90.5%	$99,836,132
Jan-13	$233,783,161	($113,347,680)	$120,435,482	$67,997,096	56.5%	$181,344,776	83.2%	$194,399,312
Feb-13	$259,657,461	($131,557,526)	$128,099,935	$77,154,565	60.2%	$208,712,090	85.4%	$221,784,584
Mar-13	$146,552,085	($75,878,638)	$70,673,447	$52,429,117	74.2%	$128,307,755	90.8%	$133,041,304
Total	$1,598,272,637	($829,035,863)	$769,236,775	$533,223,289	69.3%	$1,362,259,152	89.1%	$1,423,964,887

* Reported payout ratios may vary due to rounding differences when netting

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the first ten months of the 2012 to 2013 planning period from the reported 69.3 percent to 89.1 percent.

Figure 12-9 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through March 2013.

Figure 12-9 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through March 2013

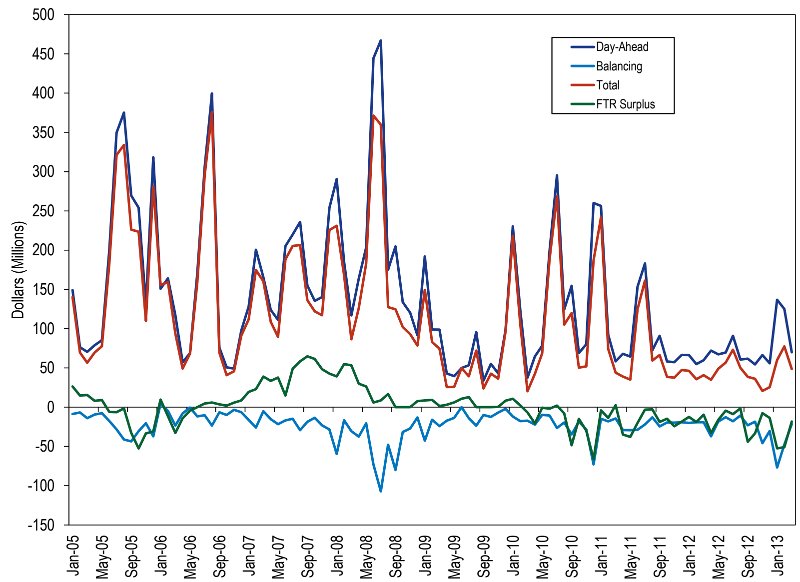
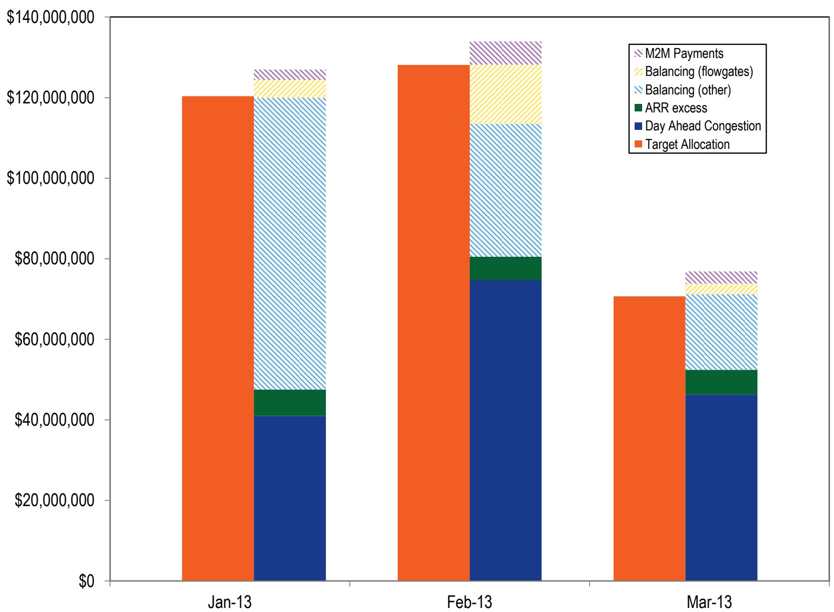


Figure 12-10 shows the monthly target allocation compared to the available positive and negative congestion revenue. The solid orange bar on the left of each month shows the monthly target allocation for all FTRs. The bar on the right of each month shows the positive and negative congestion dollars available to fund target allocations. The total height of the bar corresponds to total Day-Ahead congestion. Striped areas on this bar represent charges that reduce revenue and solid areas represent additions to revenue.

Figure 12-10 FTR target allocation compared to sources of positive and negative congestion revenue: January through March 2013



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.[19] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.[20]

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 2012 to 2013 planning period, all eligible market participants were allocated ARRs.

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.[21] 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

19 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.
20 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."
21 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

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.

There were 48,077 MW of ARRs associated with approximately $464,100 of revenue that were reassigned in the first ten months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Table 12-18 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2011 and March 2013.

Table 12-18 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2011, through March 31, 2013

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2011/2012 (12 months)	2012/2013 (10 months)*	2011/2012 (12 months)	2012/2013 (10 months)*
AECO	563	447	$4.8	$2.3
AEP	6,341	4,303	$119.0	$54.2
AP	5,516	3,382	$319.4	$80.8
ATSI	3,321	4,382	$13.3	$7.3
BGE	2,745	3,037	$45.9	$35.3
ComEd	3,804	11,094	$59.1	$160.5
DAY	463	534	$0.6	$0.8
DEOK	NA	2,609	NA	$1.4
DLCO	2,964	2,525	$10.4	$17.8
DPL	1,957	1,846	$15.4	$10.6
Dominion	1	0	$0.0	$0.0
JCPL	1,332	1,149	$10.1	$4.6
Met-Ed	1,273	986	$20.9	$7.6
PECO	1,994	3,124	$21.9	$20.8
PENELEC	1,116	835	$21.2	$7.5
PPL	3,565	2,951	$38.1	$18.7
PSEG	2,325	1,971	$31.2	$14.0
Pepco	2,489	2,903	$27.4	$20.0
RECO	73	58	$0.0	$0.0
Total	41,770	48,077	$758.9	$464.1

* Through 31-Mar-2013

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.

Effective August 1, 2012, as ordered by FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal Network Services Peak Load or Firm Transmission Reservation Levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 12-19 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 12-19 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Aug-12	4,508.2	2,460.5	54.6%	$1,026,836
Sep-12	4,696.3	2,343.1	49.9%	$1,003,031
Oct-12	6,502.2	1,698.9	26.1%	$584,810
Nov-12	3,677.8	1,530.6	41.6%	$393,221
Dec-12	7,006.6	1,614.5	23.0%	$463,325
Jan-13	6,773.0	1,547.2	22.8%	$488,251
Feb-13	1,567.4	1,493.7	95.3%	$229,856
Mar-13	5,351.2	1,522.7	28.5%	$286,193

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 12-20 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible.

Table 12-20 Constraints with capacity increases due to Stage 1A infeasibility for the 2012 to 2013 ARR Allocation

Constraint	Type	Control Zone	MW Increase
Pleasant Prairie - Zion	Flowgate	MISO	311
Breed - Wheatland	Flowgate	MISO	221
Silver Lake	Transformer	ComEd	131
Oak Grove - Galesburg	Flowgate	MISO	96
Kenosha - Lakeview	Flowgate	MISO	73
Belvidere - Woodstock	Line	ComEd	23
Harwood - Susquehanna	Line	PPL	16
Belmont	Transformer	AP	14
Nucor - Whitestown	Flowgate	MISO	7

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 total 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 total 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 received $624.6 million in credits from the FTR auctions during the first ten months of the 2012 to 2013 planning period, with an average hourly ARR credit of $0.63 per MW. During the first ten months of the 2011 to 2012 planning period, ARR holders received $1,055.9 million in ARR credits, with an average hourly ARR credit of $1.05 per MW.

Table 12-21 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 and the 2012 to 2013 (through March 31, 2013) planning periods.

Table 12-21 ARR revenue adequacy (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013

	2011/2012	2012/2013
Total FTR auction net revenue	$1,055.9	$624.6
Annual FTR Auction net revenue	$1,029.6	$602.9
Monthly Balance of Planning Period FTR Auction net revenue*	$26.3	$21.7
ARR target allocations	$947.3	$565.4
ARR credits	$947.3	$565.4
Surplus auction revenue	$108.6	$59.1
ARR payout ratio	100%	100%
FTR payout ratio*	80.6%	74.8%

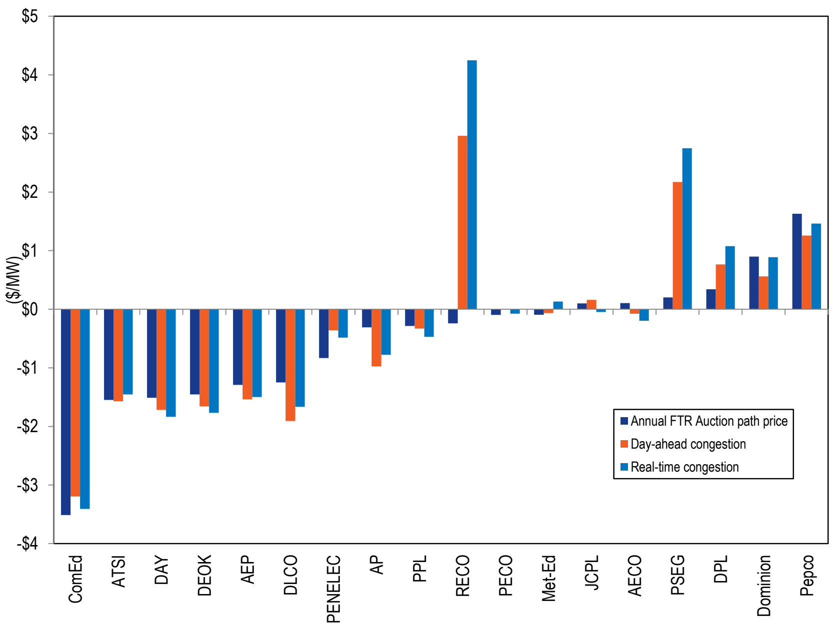
* Shows twelve months for 2011/2012 ten months for 2012/2013.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-11 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2012 to 2013 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 12-11 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub[22]: first ten months of the 2012 to 2013 planning period



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. During the first ten months of the 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset 82.1 percent of the total congestion costs within PJM.

22 DEOK was integrated into PJM on January 1, 2012 so was not available in the 2011 to 2012 Annual FTR Auction and therefore is not included in Figure 12-11.

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 12-22. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[23] 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 69.5 percent of the target allocation for the first ten months of the 2012 to 2013 planning period. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

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 revenue and the congestion for each ARR control zone sink.

23 For Table 12-22 through Table 12-24, 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.

Table 12-22 ARR and self-scheduled FTR congestion offset (in millions) by control zone: first ten months of the 2012 to 2013 planning period[24]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$5.9	$0.0	$5.9	$6.8	($0.9)	87.0%
AEP	$25.3	$51.9	$77.2	$38.2	$61.8	>100%
APS	$40.4	$20.8	$61.2	$7.3	$63.1	>100%
ATSI	$4.1	$0.2	$4.3	($4.0)	$8.4	>100%
BGE	$30.3	$0.6	$30.8	$7.3	$23.8	>100%
ComEd	$101.8	$0.0	$101.8	($45.4)	$147.2	>100%
DAY	$1.5	$1.6	$3.0	($2.7)	$6.4	>100%
DEOK	$1.1	$0.0	$1.1	($5.0)	$6.1	>100%
DLCO	$5.9	$0.2	$6.1	($0.3)	$6.5	>100%
Dominion	$4.8	$50.9	$55.7	$13.6	$64.5	>100%
DPL	$11.4	$1.3	$12.8	$27.4	($14.0)	46.6%
External	$5.7	$0.4	$6.1	$2.6	$3.7	>100%
JCPL	$9.0	$0.2	$9.1	$9.7	($0.5)	93.7%
Met-Ed	$8.7	$0.1	$8.9	$5.1	$3.8	>100%
PECO	$16.9	$1.9	$18.8	$16.5	$3.1	>100%
PENELEC	$6.9	$4.5	$11.3	$6.3	$7.0	>100%
Pepco	$24.8	$1.4	$26.2	$24.5	$2.2	>100%
PPL	$18.3	$1.1	$19.4	$6.3	$13.6	>100%
PSEG	$26.1	$7.0	$33.1	($15.4)	$51.5	>100%
RECO	$0.0	$0.0	$0.0	$1.2	($1.2)	0.1%
Total	$349.1	$143.8	$492.9	$100.1	$473.7	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 12-23 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 2012 to 2013 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 69.5 percent of the target allocation for the 2012 to 2013 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control 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 offset 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.[25] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

24 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.

25 The total zonal congestion numbers were calculated as of April 24, 2013 and may change as a result of continued PJM billing updates.

Table 12-23 ARR and FTR congestion offset (in millions) by control zone: first ten months of the 2012 to 2013 planning period

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$5.9	($0.3)	$6.5	($0.9)	$3.3	($4.2)	0.0%
AEP	$105.5	$88.8	$121.9	$72.4	$92.2	($19.9)	78.5%
APS	$76.2	$23.8	$40.1	$59.9	$71.2	($11.3)	84.1%
ATSI	$4.3	$11.3	($0.9)	$16.5	($1.1)	$17.6	>100%
BGE	$31.6	$23.1	$43.1	$11.6	$23.3	($11.6)	49.9%
ComEd	$121.4	$78.3	$81.7	$118.0	$141.3	($23.2)	83.6%
DAY	$3.8	$5.3	$5.3	$3.8	$4.7	($0.9)	81.1%
DEOK	$1.4	$5.2	$4.0	$2.6	$1.7	$0.9	>100%
DLCO	$7.2	($0.3)	$7.5	($0.5)	$2.9	($3.4)	0.0%
Dominion	$79.3	$70.2	$110.2	$39.3	$67.1	($27.8)	58.5%
DPL	$12.3	$21.4	$19.8	$13.8	$16.4	($2.6)	84.3%
External	$7.0	($0.5)	$1.7	$4.9	($23.6)	$28.5	>100%
JCPL	$9.3	$22.1	$22.0	$9.4	$12.1	($2.7)	78.0%
Met-Ed	$9.0	$7.3	$16.0	$0.3	$1.9	($1.6)	17.0%
PECO	$20.1	$12.7	$17.7	$15.1	($0.9)	$15.9	>100%
PENELEC	$11.8	$23.6	$30.0	$5.4	$34.7	($29.2)	15.6%
Pepco	$27.1	$35.0	$83.1	($21.0)	$29.6	($50.7)	0.0%
PPL	$21.0	$4.3	$9.6	$15.6	$11.6	$4.0	>100%
PSEG	$24.0	$97.5	$34.5	$87.0	$16.0	$71.0	>100%
RECO	$0.0	$1.6	($1.8)	$3.3	$4.1	($0.8)	81.1%
Total	$578.3	$530.1	$651.9	$456.6	$508.6	($52.0)	89.8%

Table 12-24 shows the total offset due to ARRs and FTRs for the entire 2011 to 2012 planning period and the first ten months of the 2012 to 2013 planning period.

Table 12-24 ARR and FTR congestion hedging (in millions): Planning periods 2011 to 2012 and 2012 to 2013 through March 31, 2013[26]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2011/2012	$982.9	$794.3	$1,092.4	$684.8	$771.2	($86.4)	88.8%
2012/2013*	$578.3	$530.1	$651.9	$456.6	$508.6	($52.0)	89.8%

* Shows ten months ended 31-Mar-13

26 The FTR credits do not include after-the-fact adjustments. For the 2012 to 2013 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.