Q3

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.14.2013

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 September.*

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).

Introduction

2013 Q3 in Review

The state of the PJM markets in the first nine 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 nine 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 continued in the first three quarters 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. Information about the sources of operating reserve charges is notably opaque.

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 energy market dynamics changed in the first nine months of 2013. A combination of increased, weather related, demand, and higher fuel costs led to higher energy market prices than in the first three quarters of 2012. The load-weighted average LMP was $39.75 per MWh, 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012.

The price of natural gas was higher and the price of coal was relatively flat in the first nine months of 2013 compared to the first nine months of 2012. For example, the price of Northern Appalachian coal was 0.4 percent lower and the price of Central Appalachian coal was 2.8 percent higher, while the price of eastern natural gas was 54.0 percent higher. The price of natural gas, especially in the eastern part of PJM, increased in January but then decreased.

The results of the energy market dynamics in the first nine months of 2013 were generally positive for new coal units. As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units. Coal-fired units' output increased by 6.2 percent in the first nine months of 2013 and gas-fired units' output decreased by 16.1 percent in the same period, reversing the trend towards reduced coal output.

The combination of higher energy prices and higher gas prices relative to coal prices resulted in significantly higher energy market net revenues for a new entrant coal plant in all PJM zones. In the first nine months of 2013, average energy market net revenues for a new entrant coal plant were 133 percent greater than in the first nine months of 2012 while average energy market net revenues for a new entrant gas fired combined cycle unit were 15 percent lower.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need good information about constraints that can have substantial impacts on energy prices. For example, the markets need better information about unit outages in order to improve market transparency. For example, the markets need better information about transmission outages in order to improve market transparency. 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. Recent rule changes to improve the availability of information about unit retirements will make information available to potential entrants and increase the competitiveness of the capacity market.

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, the continued inclusion of inferior demand side products that also suppress market prices and the role of imports.

The fact that up to congestion transactions are provided an artificial advantage over other virtual transactions must be addressed.

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, January through September 2012 and 2013[1]

	Jan - Sep 2012	Jan - Sep 2013
Load	591,517 GWh	592,209 GWh
Generation	602,561 GWh	600,784 GWh
Imports (+) / Exports (-)	801 GWh	3,474 GWh
Losses	12,778 GWh	13,218 GWh
Regulation Requirement*	943 MW	784 MW
RTO Primary Reserve Requirement	NA	2,063 MW
Total Billing	$22.12 Billion	$25.16 Billion
Peak	Jul 17, 2012 17:00	Jul 18, 2013 17:00
Peak Load	154,344 MW	157,508 MW
Load Factor	0.58	0.57
Installed Capacity	As of 9/30/2012	As of 9/30/2013
Installed Capacity	185,841 MW	185,085 MW

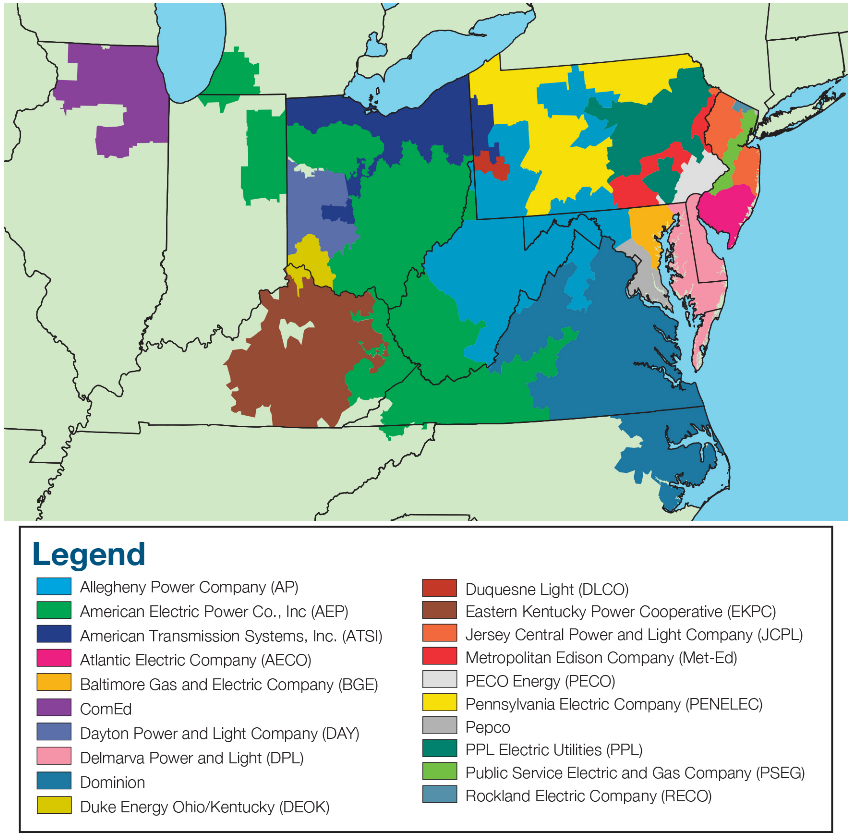
* Daily average

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2013, had installed generating capacity of 185,560 megawatts (MW) and 877 members including market buyers, sellers and traders of electricity in a region including more than 60 million people 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). [2,3,4] In the first nine months of 2013, PJM had total billings of $25.16 billion, up from $22.12 billion in the first nine months of 2012.[5] 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.

1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 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>.
5 Monthly billing values are provided by PJM.

Figure 1-1 PJM's footprint and its 20 control zones



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.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine 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.

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

6 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>.

7 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. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) 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."

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 nine 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 nine months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1180 with a minimum of 871 and a maximum of 1610 in the first nine 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.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9]

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. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a 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 September, 2013

	January through September 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 year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in January through September, 2013.

8 OATT Attachment M.
9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of 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.

- Participant behavior in the Regulation Market was evaluated as competitive for January through September, 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 are inefficient 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. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement[12]. It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

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 MMU estimates that the Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 5.6 percent of the hours in January through September, 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), 15 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.

12 On October 2, 2013 FERC issued an order directing PJM to compensate regulating resources (the portion of each resource's compensation based on performance) based on a mileage ratio multiplier. This ratio will be the hourly mileage of the RegD signal / mileage of the RegA signal. This ratio increases the regulation performance compensation paid to high performing resources compared with regular resources. Between October 2012 and September 2013 the average mileage ratio has been 3.11 compared to an average marginal benefit factor of 2.63. PJM will begin to settle the regulation market (performance segment) using the mileage ratio on November 1, 2013. PJM will then recalculate performance regulation settlement for the purpose of adjusting the credits from October 1, 2012, through October 31, 2013. The regulation performance clearing price will not change.

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

- 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.
- Market 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. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[13] 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.[14]

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.

13 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).

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

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.[15] The MMU has direct, confidential access to the FERC.[16] The MMU may also refer matters to the attention of state commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules.[18] 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, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[19,20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[22] 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 and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[23,24] 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).[25] 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.[26]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[27,28,29,30]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[31] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they

15 OATT Attachment M § IV.
16 OATT Attachment M § IV.K.3.
17 OATT Attachment M § IV.H.
18 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.")
19 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.
20 OATT Attachment M § II(h-1).
21 OATT Attachment M § IV.C.
22 OATT Attachment M § IV.I.1.
23 *Id.*
24 *Id.*

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

may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[32] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

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.[33] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[34] 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.[35] 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.[36] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[37]

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 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.

32 OATT § 12A.
33 OATT Attachment M § IV.D.
34 *Id.*
35 *Id.*
36 *Id.*
37 OATT Attachment M § VI.A.

Table 1-8 Prioritized summary of new recommendations

Priority	Section	Description
Medium	4 - Operating Reserves	Reflect impact of all physical constraints in market prices.
High	5 - Capacity	Increase the Capacity Resource Deficiency Charge.
High	5 - Capacity	Require PJM to sell excess capacity, if necessary, in Incremental Auctions at the BRA clearing price.
High	5 - Capacity	Eliminate requirement for First and Second Incremental Auctions.
High	5 - Capacity	Define Market Seller Offer Cap for First and Second Incremental Auctions, if held, as higher of 1.0 times the Base Residual Auction clearing price or ACR.
High	5 - Capacity	Enforce the rules governing the requirement to be a physical resource for all resource types.
Low	6 - Demand Response	Adopt the ISO-NE demand response metering requirements.
Low	6 - Demand Response	The MMU recommends that demand resources be required to provide their nodal location.
Low	9 - Interchange Transactions	Align interface pricing definitions between PJM and MISO.
Medium	9 - Interchange Transactions	Eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
Low	9 - Interchange Transactions	Eliminate the NIPSCO and Southeast interface pricing points.
High	10 - Ancillary Services	Eliminate rule paying for Tier 1 MW at Tier 2 clearing price when the non-synchronized reserve price is above $0.
High	13 - FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

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 nine 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 94.6 percent of the total price per MWh in the first nine 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.[38]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[41]
- 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.[42]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[43]
- 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.[44]
- 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.[45]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[46]
- The Black Start component is the average cost per MWh of black start service.[47]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[48]

38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 Reliability Assurance Agreement Schedule 8.1.
44 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
45 OATT Schedule 1A.
46 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
47 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.
48 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]

Table 1-9 Total price per MWh by category: January through September 2012 and 2013

Category	Jan-Sep 2012 $/MWh	Jan-Sep 2013 $/MWh	Percent Change Totals	Jan-Sep 2012 Percent of Total	Jan-Sep 2013 Percent of Total
Load Weighted Energy	$35.02	$39.75	13.5%	71.4%	73.1%
Capacity	$6.27	$6.56	4.8%	12.8%	12.1%
Transmission Service Charges	$4.69	$5.09	8.4%	9.6%	9.4%
Reactive	$0.44	$0.69	57.0%	0.9%	1.3%
Operating Reserves (Uplift)	$0.75	$0.66	(12.0%)	1.5%	1.2%
PJM Administrative Fees	$0.44	$0.43	(0.8%)	0.9%	0.8%
Transmission Enhancement Cost Recovery	$0.32	$0.39	24.1%	0.6%	0.7%
Capacity (FRR)	$0.63	$0.12	(81.0%)	1.3%	0.2%
Regulation	$0.23	$0.27	16.7%	0.5%	0.5%
Black Start	$0.02	$0.14	491.5%	0.0%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(2.6%)	0.2%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.06	$0.08	23.5%	0.1%	0.1%
Synchronized Reserves	$0.03	$0.04	20.9%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	(0.8%)	0.0%	0.0%
Load Response	$0.01	$0.01	30.3%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(0.2%)	0.0%	0.0%
Non-Synchronized Reserves	NA	$0.00	NA	NA	0.0%
Transmission Facility Charges	$0.00	$0.00	21.2%	0.0%	0.0%
Total	$49.03	$54.36	10.9%	100.0%	100.0%

49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
50 OA Schedule 1 § 3.6.
51 OA Schedule 1 § 5.3b.
52 OA Schedule 1 § 3.2.3A.001.

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Average offered supply increased by 2,646, or 1.5 percent, from 173,414 MW in the first nine months of 2012 to 176,060 MW in the first nine months of 2013.[53] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 731 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 7 units (476.9 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first nine months of 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for the first nine months of 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[54]
- **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 for Energy.** PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. PJM 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 nine 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 Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in the first nine months of

53 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
54 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).

2012 to 0.2 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first nine months of 2012 to 0.5 percent in the first nine months of 2013.

- **Reliability and Offer Capping.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.5 percent in the first nine months of 2012 to 3.0 percent in the first nine months of 2013. In the Real-Time Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.2 percent in the first nine months of 2012 to 3.8 percent in the first nine months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 81 units eligible for FMU or AU status in at least one month during the first nine months of 2013, 24 units (29.6 percent) were FMUs or AUs for all nine months, and 16 units (19.8 percent) qualified in only one month of 2013.
- **Local Market Structure.** In the first nine months of 2013, 10 Control Zones experienced congestion resulting from one or more constraints binding for 75 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 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 adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer.

  In the first nine months of 2013, the unadjusted markup was negative, -$1.21 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. The adjusted markup was positive, $0.27 per MWh or 0.7 percent of the PJM real-time, load-weighted average LMP.

  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 nine months of 2013 increased by 0.5 percent from the first nine months of 2012, from 88,687 MW to 89,123 MW. The PJM average real-time load in 2013 would have decreased by 0.2 percent from the first nine months of 2012, from 88,687 MW to 88,522 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[55]

  PJM average day-ahead load in the first nine months of 2013, including DECs and up-to congestion transactions, increased by 9.5 percent from the first nine months of 2012, from 132,494 MW to 145,139 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 9.1 percent from the first nine months of 2012, from 132,494 MW to 144,501 MW, if the EKPC Transmission Zone had not been included. The day-ahead load growth was 1,800.0 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

55 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

- **Generation.** PJM average real-time generation in the first nine months of 2013 increased by 0.1 percent from the first nine months of 2012, from 90,367 MW to 90,432 MW. The PJM average real-time generation in the first nine months of 2013 would have decreased by 0.5 percent from the first nine months of 2012, from 90,367 MW to 89,910 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead generation in the first nine months of 2013, including INCs and up-to congestion transactions, increased by 9.8 percent from the first nine months of 2012, from 135,213 MW to 148,489 MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 9.4 percent from the first nine months of 2012, from 135,213 MW to 147,895 MW, if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 9,700.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first nine months of 2013, coal units provided 44.5 percent, nuclear units 34.5 percent and gas units 16.5 percent of total generation. Compared to the first nine months of 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 0.9 percent, and generation from gas units decreased 16.1 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 nine 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 nine months of 2013 compared to the first nine months of 2012. The system average LMP was 15.0 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.30 per MWh versus $32.45 per MWh. The load-weighted average LMP was 13.5 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.75 per MWh versus $35.02 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2013 compared to the first nine months of 2012. The system average LMP was 16.6 percent higher in the first nine months of 2013 than in the first nine months of 2012, $37.50 per MWh versus $32.16 per MWh. The load-weighted average LMP was 15.1 percent higher in the first nine months of 2013 than in the first nine months of 2012, $39.49 per MWh versus $34.29 per MWh.[56]

- **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 nine months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 24.1 percent by spot market purchases and 65.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot market purchases increased by 0.9 percentage points and reliance on self-supply decreased by 2.3 percentage points. For the first nine months of 2013, 7.5 percent of day-ahead load was supplied by bilateral contracts, 23.4 percent by spot market purchases, and 69.1 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot market purchases increased by 1.1 percentage points, and reliance on self-supply decreased by 1.9 percentage points.

Scarcity

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

56 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."

Section 3 Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[57] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[58]
- 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 changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders are no longer required to serve the purpose for which they were created, and the adders now interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during Maximum Emergency Events.[59]

57 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

58 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.

Section 3 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine 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 2,646 MW in the first nine months of 2013 compared to the first nine months of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. 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

59 PJM Tariff, 6A.1.3 Maximum Emergency p. 1645, 1699-1700.

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 nine 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.[60] 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.

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 nine months of 2013.

Overview: Section 4, "Operating Reserve"

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 33.7 percent in the first nine months of 2013 compared to the first nine months of 2012, to a total of $652.9 million.

  Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 48.3 percent, reactive services charges were 29.8 percent, synchronous condensing charges were 0.06 percent and black start services charges were 10.6 percent of total operating reserve charges in 2013.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh. The day-ahead operating reserve rate including

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

unallocated congestion charges averaged $0.118 per MWh. The balancing operating reserve reliability rates averaged $0.052, $0.031 and $0.004 per MWh for the RTO, Eastern and Western Regions. The balancing operating reserve deviation rates averaged $0.886, $2.193 and $0.118 per MWh for the RTO, Eastern and Western Regions. The lost opportunity cost rate averaged $0.861 per MWh and the canceled resources rate averaged $0.001 per MWh.

- **Reactive Service Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $1.952, $1.557 and $0.631 per MWh. The reactive transfer interface support rate averaged $0.141 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 46.7 percent of all day-ahead generator credits and 52.6 percent of all balancing generator credits. Combustion turbines and diesels received 73.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 91.4 percent of all reactive services credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2013, 81.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.1 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first nine months of 2013, 81.6 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.1 percent by transactions at hubs and aggregates and 12.3 percent by transactions at interfaces.
- Generators in the Eastern Region paid 15.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 75.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 13.9 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 24.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators paid 9.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.96 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 34.5 percent of all credits. The top 10 organizations received 86.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5343, balancing operating reserves HHI was 3927 and lost opportunity cost HHI was 4699.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2013, 4.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 65.4 percent was made whole.
- **Lost Opportunity Cost Credits:** In the first nine months of 2013, lost opportunity cost credits decreased by $66.0 million compared to the first nine months of 2012. In the first nine months of 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 60.7 percent of all lost opportunity cost credits, 53.6 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.6 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 53.9 percent of the credits 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 nine months of 2013, lost opportunity cost credits would have been reduced by an additional $21.3 million, or 26.1 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 in order to provide black start services even if the units are not economic. In the first nine months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $68.7 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.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in the first nine months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.218 per MWh, which is $3.564 per MWh, 94.2 percent, less than the actual average rate paid.

Section 4 Recommendations

- The MMU recommends that the impact of physical constraints of all types be reflected in market prices to the maximum extent possible, reducing the necessity for out of market operating reserve payments and improving the efficiency of market prices.
- The MMU recommends 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.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - 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.
  - 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.
  - 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.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by location and the detailed reasons for the level of operating reserve payments by location in the PJM region.

Section 4 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.[61] 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 netting of transactions against internal bilateral transactions should be eliminated.

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.

61 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," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

Overview: Section 5, "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.[62]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[63] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[64] 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.[65]

RPM prices are locational and may vary depending on transmission constraints.[66] 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 September 30, 2013, PJM installed capacity increased 3,073.8 MW or 1.7 percent from 182,011.1 MW on January 1 to 185,084.9 MW on September 30. 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 September 30, 2013, 41.9 percent was coal; 28.9 percent was gas; 17.9 percent was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.
- **Market Concentration.** In the 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First 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.[67,68,69]

62 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 Quarterly State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
63 See 126 FERC ¶ 61,275 (2009) at P 86.
64 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
65 See 126 FERC ¶ 61,275 (2009) at P 88.
66 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.
67 See OATT Attachment DD § 6.5.
68 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.
69 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).

- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 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 (3,193.8 MW).

Market Conduct

- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2014/2015 RPM Second Incremental Auction and the 2015/2016 RPM First Incremental Auction were conducted in the third quarter of 2013. In the 2014/2015 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $25.00 per MW-day. The weighted average capacity price for the 2014/2015 Delivery Year is $127.74, including all RPM Auctions for the 2014/2015 Delivery Year held through the first nine months of 2013. In the 2015/2016 First Incremental Auction, the RTO clearing price for Annual Resources was $43.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $160.03, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2013.
- The delivery year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through September was 8.0 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[70]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through September was 84.2 percent, a slight increase from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2013, 34.3 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 5 Conclusion

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first nine months of 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in

70 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 nine months ending September 30, as downloaded from the PJM GADS database on October 22, 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.

the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of 2013.[71]

Overview: Section 6, "Demand Response"

- **Demand Response Activity.** In the first nine months of 2013, total load reduction under the Economic Load Response Program decreased by 7,002 MWh compared to the same period in 2012, from 121,381 MWh in the first nine months of 2012 to 114,379 MWh in the first nine months of 2013, a six percent decrease. Total credits under the Economic Program decreased by $1,084,448, from $8,172,654 in the first nine months of 2012 to $7,088,205 in the same period of 2013, a 13 percent decrease. September 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.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first nine months of 2013, Load Management (LM) Program revenue increased $33.8 million, or 12.8 percent, compared to the same period of 2012, from $263.6 million to $297.4 million in 2013.

  In the first nine months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.9 million, or 54.2 percent, compared to the same period in 2012, from $3.6 million to $1.6 million in 2013.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis, defined by zip codes. More locational deployment of demand-side resources improves efficiency in a nodal market.

- **Load Management Product.** The load management product is currently defined as an emergency product. The load management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

- **Emergency Event Day Analysis.** Load management event rules allow over compliance to be reported when there is no actual over compliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the five events in 2013 should have been 5,116.9 MW, rather than the 5,644.7 MW reported. Overall, compliance decreases from the reported 100.5 percent to 90.6 percent. This does not include locations that did not report their load during the emergency event days.

Section 6 Conclusion

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.

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

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 be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, 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.[72] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and receives the market clearing price. 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.[73]

More locational deployment of Load Management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event. The MMU also recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to DR resources are based on actual metered data.[74]

Overview: Section 7, "Net Revenue"

Net Revenue

- In the first nine months of 2013, average energy market net revenues for a new entrant CT were three percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant CC were 15 percent less than in 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant coal plant were 133 percent greater than in the first nine months of 2012. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.
- In the first nine months of 2013, average energy market net revenues for a new entrant wind plant were 15 percent greater than in the first nine months of 2012.
- In the first nine months of 2013, average energy market net revenues for a new entrant solar plant were 40 percent greater than in the first nine months of 2012.

Section 7 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

72 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."
73 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.
74 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response" <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR resource have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, Demand Response resources in ISO-NE must also be registered at a single node.

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.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets.

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.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[75] 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.[76] The rule establishes a compliance deadline of April 16, 2015.

  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. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[77]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state 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.

  On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the most recently issued rule limiting interstate emissions, the Cross-State Air Pollution Rule (CSAPR), which previously had been subject to a stay.[78] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, 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

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

76 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

77 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

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

engines (RICE).[79] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. 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 September 20, 2013, EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[80] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[81]

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.[82] New Jersey's HEDD rule, 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.[83]

- **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 an average of $2.89 per ton, above the price floor for 2013. The clearing price is equivalent to a price of $3.19 per metric tonne, the unit used in other carbon markets.

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 June 30, 2013, 69.4 percent of coal steam MW 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, and 91.3 percent of fossil fuel fired capacity in PJM had 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 September 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. 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.

79 *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, 78 Fed. Reg. 9403 (January 30, 2013).
80 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Propose Rule, EPA-HQ-OAR-2013-0495.
81 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
82 N.J.A.C. § 7:27-19.
83 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).

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. 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 LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 8 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 9, "Interchange Transactions"

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and a net exporter of energy in September.[84] During the first nine months of 2013, the real-time net interchange of 4,706.7 GWh was greater than net interchange of 2,152.5 GWh in the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2013, the total day-ahead net interchange of -12,727.7 GWh was greater than net interchange of -5,824.8 GWh during the first nine months of 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2013, gross imports in the Day-Ahead Energy Market were 150.8 percent of gross imports in the Real-Time Energy Market (403.2 percent during the first nine months of 2012), gross exports in the Day-Ahead Energy Market were 218.5 percent of the gross exports in the Real-Time Energy Market (447.5 percent during the first nine months of 2012).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[85]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months

84 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
85 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

of 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2013, up-to congestion transactions had net exports at seven of PJM's 19 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 nine months of 2013, the direction of the average hourly flow was consistent 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 47.0 percent of hours in the first nine months of 2013.

- **PJM and New York ISO Interface Prices.** In the first nine 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 53.1 percent of the hours in the first nine months of 2013.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine 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.[86] The average hourly flow during the first nine months of 2013 was -354 MW.[87] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 69.5 percent of the hours in the first nine months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine 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.[88] The average hourly flow during the first nine months of 2013 was -127 MW.[89] The direction of flows was consistent with price differentials in 65.8 percent of the hours in the first nine months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first four months of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[90] The average hourly flow during the first four months of operation was -22 MW.[91] The direction of flows was consistent with price differentials in 60.9 percent of the hours between June 3, 2013 and September 30, 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 nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. For the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. This difference is inadvertent interchange.

86 In the first nine months of 2013, there were 1,128 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 $42.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $64.19, a difference of $21.57.

87 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -428 MW.

88 In the first nine months of 2013, there were 1,351 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 $41.23 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.95, a difference of $7.72.

89 The average hourly flow during the first nine months of 2013, ignoring hours with no flow, on the Linden VFT line was -161 MW.

90 In its four months of operation, there were 2,987 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $48.65 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.00, a difference of $6.35.

91 The average hourly flow during the first four months of operations, ignoring hours with no flow, on the Hudson line was -120 MW.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 45 TLRs of level 3a or higher in the first nine months of 2013, compared to 29 TLRs issued in the first nine months of 2012.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 105,472 bids per day, with an average cleared volume of 1,221,114 MWh per day, in the first nine months of 2013, compared to an average of 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012.
- **Elimination of Ontario Interface Pricing Point.** The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing. Because 5,000 GWh of the 5,023 GWh of the net scheduled transactions between PJM and IESO wheeled through MISO during the first nine months of 2013, the MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority until the stakeholder process determines an alternative approach to pricing these transactions.
- **PJM and NYISO Coordinated Interchange Transaction Proposal.** The Coordinated Transaction Scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's Intermediate Term Security Constrained Economic Dispatch tool (ITSCED) and the NYISO's Real Time Commitment (RTC) tool.

  CTS transactions are evaluated based on the spread bid, which limits the amount price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to proceed with the development of the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.
- **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.[92] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.
- **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 unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

Section 9 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-

92 See "Meeting Minutes, "Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx> (Accessed October 9, 2013).

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 offsets (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 nine 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. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first nine 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 53.0 percent of the hours for transactions between PJM and MISO and for 46.9 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.

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.

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 which can create loop flows and inaccurate pricing for transactions. 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.

The non-contiguous nature of the Ontario Interface Pricing Point creates double payments or double credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.

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. The level of the fee should be determined based on the method defined in the State of the Market Report.[93]

There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created at the NIPSCO interface prior to the integration.

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.[94] After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM no longer accept long term positions of any kind at the NIPSCO and Southeast interface pricing points and to eliminate these interface pricing points from the Day-Ahead and Real-Time Energy Markets.

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.[95] 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.

The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

93 See the *2013 Quarterly State of the Market Report for PJM: January through September*, Section 4, "Operating Reserves."

94 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 October 10, 2013).

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

Overview: Section 10, "Ancillary Services"

Regulation Market

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

Market Structure

- **Supply.** In January through September 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 3.67. This is a 14.7 percent increase over January through September 2012 when the ratio was 3.20.
- **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 September, 2013, was 784 MW. This is a 214 MW decrease in the average hourly regulation demand of 998 MW in the same period of 2012.
- **Market Concentration.** In January through September 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2063 which is classified as highly concentrated.[96] In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (44 percent of hours failed the three pivotal supplier test in January through September 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 cost 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.[97] As of September 30, 2013, there were 22 resources offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted average Regulation Market Clearing Price for the PJM Regulation Market for January through September 2013 was $32.72. This is an increase of $17.80, or 119.3 percent, from the weighted average price for regulation in January through September 2012. The cost of regulation from January through September 2013 was $37.35. This is a $16.77 (81.5 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 incorporated the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated the Dominion Zone to become the Mid-Atlantic Dominion Reserve Zone. PJM has the right to define new zones or subzones "as needed for system reliability."[98]

Market Structure

- **Supply.** In January through September, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of Demand Response (DR) to the Synchronized Reserve Market remains significant. Demand 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 Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration

96 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.

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

98 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 61 (June 27, 2013), p. 66.

of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit distribution factor (DFAX) values across the interface consistent with the way these values are calculated in the energy market. Additionally, PJM calculates the most limiting interface in real time for each market optimization, ASO, IT-SCED and RT-SCED. For most hours it is Bedington – Black Oak. The second most common limiting interface is AP South.

- **Market Concentration.** For January through September 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4372 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through September, 2012, was 3202, which is classified as "highly concentrated."[99] In January through September, 2013, 58 percent of hours had a maximum market share greater than 40 percent, compared to 45 percent of hours in January through September, 2012.

  In the Mid-Atlantic Dominion Subzone, in January through September, 2013, the MMU estimates that 5.6 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through September, 2012, the MMU estimates that 24 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 September 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 Dominion Subzone was $6.86 per MW in January through September, 2013, a decrease of three percent over January through September 2012. The total cost of synchronized reserves per MW in January through September 2013 was $14.82, a 35 percent increase from the $10.92 cost of synchronized reserve in January through September 2012. The market clearing price was 51 percent of the total synchronized reserve cost per MW in January through September 2013, down from 64 percent in January through September 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 January through September period of 2013. Although supplies were always adequate to meet demand, an extended spinning event on September 10 raised concerns that the current method for estimating Tier 1 is incorrect. PJM has initiated studies designed to improve the accuracy of Tier 1 estimation. It is expected that by January 1, 2014, the amount of Tier 1 estimated, especially during periods of high demand, will decrease as a result of changes to the estimation method.

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

DASR

The purpose of the DASR Market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[100] 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 September, 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 providing DASR. As of September 30, 2013, 15 percent of offers reflected economic withholding. PJM rules require that all units with reserve capability that can be converted into energy within 30 minutes offer into the DASR Market.[101] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through September, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through September 2013 was $0.93 per MW. In January through September 2012, the weighted price of DASR was $0.75 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.[102]

In January through September 2013 black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23. shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.08 per MW.

Section 10 Conclusion

The design of the Regulation Market changed 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 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 three quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

100 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.
101 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.
102 OATT Schedule 1 § 1.3BB.

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. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

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

Overview: Section 11, "Congestion and Marginal Losses"

Energy Cost

- **Total Energy Costs.** Total energy costs in the first nine months of 2013 decreased by $85 million or 19.2 percent from the first nine months of 2012, from -$442.6 million to -$527.6 million. Day-ahead net energy costs in the first nine months of 2013 decreased by $171.9 million or 40.0 percent from the first nine months of 2012, from -$429.8 million to -$601.6 million. Balancing net energy costs in the first nine months of 2013 increased by $98.9 million or 478.0 percent from the first nine months of 2012, from -$20.7 million to $78.2 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 nine months of 2013 ranged from -$90.8 million in July to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first nine months of 2013 increased by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 million. Day-ahead net marginal loss costs in the first nine months of 2013 increased by $95.5 million or 12.3 percent from the first nine months of 2012, from $776.0 million to $871.5 million. Balancing net marginal loss costs decreased in the first nine months of 2013 by $56.1 million or 303.8 percent from the first nine months of 2012, from -$18.5 million to -$74.6 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 nine months of 2013 ranged from $66.2 million in April to $142.1 million in July.

- **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 netresidual market adjustments, which is paid back in full to load and exports on a load ratio basis.[103] The marginal loss credits decreased in the first nine months of 2013 by $46.0 million or 14.7 percent from the first nine months of 2012, from $313.3 million to $267.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $83.5 million or 19.6 percent, from $425.2 million in the first nine months of 2012 to $508.7 million in the first nine months of 2013.[104]
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $197.3 million or 32.7 percent, from $603.2 million in the first nine months of 2012 to $800.5 million in the first nine months of 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $113.8 million or 63.9 percent from -$178.0 million in the first nine months of 2012 to -$291.8 million in the first nine months of 2013.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2013 ranged from $27.8 million in March to $109.2 million in July.
- **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 West interface, the ATSI interface, the Bridgewater - Middlesex line, the Cloverdale transformer.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first nine months of 2013. Day-ahead congestion frequency increased by 54.1 percent from 168,509 congestion event hours in the first nine months of 2012 to 259,605 congestion event hours in the first nine months of 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency decreased by 6.0 percent from 15,153 congestion event hours in the first nine months of 2012 to 14,249 congestion event hours in the first nine months of 2013. Real-time, congestion-event hours increased on the interfaces and the flowgates, while congestion on the transformers, and the transmission lines decreased.

  Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first nine months of 2013, for only 2.0 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first nine months of 2013, for 37.9 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 nine months of 2013. With $144.1 million in total congestion costs, it accounted for 28.3 percent of the total PJM congestion costs in the first nine months of 2013. The top five constraints in terms of congestion costs together contributed $183.8 million, or 36.1 percent, of the total PJM congestion costs in the first nine months of 2013. The top five constraints were the AP South interface, the West interface, the ATSI interface, the Bridgewater – Middlesex line, and the Cloverdale transformer.
- **Zonal Congestion.** ComEd was the most congested zone in the first nine months of 2013. ComEd had -$337.8 million in total load costs, -$472.5 million in total generation credits and -$14.1 million in explicit congestion, resulting in $120.5 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

103 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

104 The total zonal congestion numbers were calculated as of October 14, 2013, and are based on continued PJM billing updates, subject to change.

Nelson – Cordova line, the Byron - Cherry Valle flowgate, the AP South interface, the Braidwood transformer, and the Crete - St Johns Tap flowgate contributed $44.1 million, or 36.6 percent of the total ComEd Control Zone congestion costs.

The AEP Control Zone was the second most congested zone in PJM in the first nine months of 2013, with $76.5 million. The AP South interface contributed $20.0 million or 27.4 percent of the total AP Control Zone congestion cost in first nine months of 2013. The AP Control Zone was the third most congested zone in PJM in the first nine months of 2013, with a cost of $74.3 million.

- **Ownership.** In the first nine 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 nine months of 2013, financial companies received $84.1 million in net congestion credits, an increase of $16.8 million or 25.0 percent compared to the first nine months of 2012. In the first nine months of 2013, physical companies paid $592.8 million in net congestion charges, an increase of $100.3 million or 20.4 percent compared to the first nine months of 2012.

Section 11 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 nine months of 2013 compared to the first nine months of 2012. Total marginal loss costs increased in the first nine months of 2013 by $39.4 million or 5.2 percent from the first nine months of 2012, from $757.6 million to $796.9 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 85.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 67.8 percent of the target allocation level for the 2012 to 2013 planning period, and at 77.3 percent of the target allocation level for the 2013 to 2014 planning period through September 30, 2013.[105] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At September 30, 2013, 63,765 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in the first nine months of 2013. Wind projects account for 16,442 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 37,634 MW of capacity or 59.0 percent of the capacity in the queues.
- **Generation Retirements.** There are 22,070.4 MW planned to be retired between 2011 and 2019, with all but 614.5 MW retired by June, 2015. The AEP zone accounts for 3,560 MW, or 32.7 percent of all MW planned for deactivation from 2013 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI zone.

105 See the *2012 State of the Market Report for PJM, Volume II:* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014."

- **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 Eastern MAAC (EMAAC) and Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[106] 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.[107] 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 15,726 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.

Regional Transmission Expansion Plan (RTEP)

- On October 3, 2013, the PJM Board of Managers authorized $1.2 billion in transmission upgrades and improvements that were identified as part of PJM's continued regional planning process.

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

Section 12 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 No. 1000, there is not yet a robust mechanism to permit competition

106 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones. SWMAAC consists of the BGE and Pepco Control Zones. See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

107 OATT Parts IV & VI.

108 *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).

among transmission developers to build transmission projects.[109] 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.

The PJM queue evaluation process needs to be enhanced to ensure that barriers to competition are not created. There appears to be a substantial amount of non-viable MW in the queues, which increase interconnection costs for projects behind them. The MMU recommends the establishment of a PJM review process to ensure that projects are removed from the queue, if they are not viable.

Overview: Section 13, "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 2013 to 2014 planning period through September 30, 2013, total participant FTR sell offers were 2,334,947 MW, up from 2,217,995 MW for the same period during the 2012 to 2013 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 5.9 percent from 9,223,203 MW for the first four months of the prior planning period, to 9,765,083 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 75.6 percent of prevailing flow and 85.7 percent of counter flow FTRs for January through September of 2013. Financial entities owned 62.2 percent of all prevailing and counter flow FTRs, including 53.4 percent of all prevailing flow FTRs and 79.4 percent of all counter flow FTRs during the January through September 2013 period.

Market Behavior

- **FTR Forfeitures.** Total forfeitures of FTR profits resulting from the FTR forfeiture rule for the 2013 to 2014 planning period, through August 2013, were $440,526 for Increment Offers and Decrement Bids.
- **Credit Issues.** Eight participants defaulted in 2013, through August, from twelve default events. The average of these defaults was $320,125 with nine based on inadequate collateral and three based on nonpayment. The average collateral default was $377,579 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the 2013 to 2014 planning period, through September 2013, the Monthly Balance of Planning Period FTR Auctions cleared 1,308,752 MW (13.4 percent) of FTR buy bids and 443,885 MW (19.0 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, through September 2013, was $0.07, down from $0.11 per MW for the same time period in the 2012 to 2013 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $7.3 million in net revenue for all FTRs for the first four months of the 2013 to 2014 planning period, down from $11.9 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 77.3 percent

109 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

of the target allocation level for the first four months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the 2013 to 2014 planning period through September 30, 2013 and $614.0 million during the 2012 to 2013 planning period.

For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Vienna and 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 $138.8 million in profits for physical entities, of which $134.0 million was from self-scheduled FTRs, and $132.1 million for financial entities. 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. For the 2013 to 2014 planning period, through September 2013, PJM allocated a total of 11,586.4 MW of residual ARRs with a total target allocation of $3.3 million.

- **ARR Reassignment for Retail Load Switching.** There were 25,157 MW of ARRs associated with approximately $125,800 of revenue that were reassigned in the first four months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2013 to 2014 planning period, the ARR target allocations were $503.4 million while PJM collected $559.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $565.4 million while PJM collected $614.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate for that period.

- **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 2013 to 2014 planning period through September 30, 2013, the total revenues received by ARR holders, including self-scheduled FTRs, offset 85.5 percent of 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 the holders of all ARRs and FTRs offset more than 92.6 percent of the total congestion costs within PJM and for the 2011 to 2012 planning period 88.9 percent.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.

- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.

Section 13 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. ARRs now serve that function. 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. In the PJM model, FTRs are a financial product that PJM makes available when excess transmission capability permits.

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. ARR holders do have those rights based on their payment for the transmission system. 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 modeling differences between the day-ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013 the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly 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. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 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 2012 to 2013 planning period from the reported 67.8 percent to 88.6 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 in the FTR auction model 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, which directly results in differences in congestion between day ahead and real time markets; 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, which directly results in differences in congestion between day ahead and real time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.

