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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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2011

PREFACE

The PJM Market Monitoring Plan provides:

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

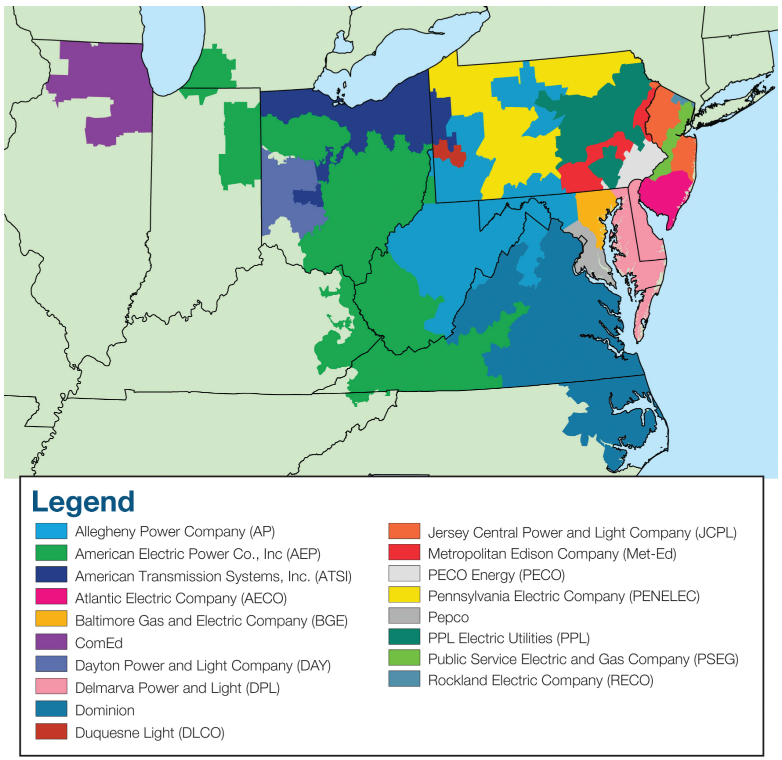
Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2011 Quarterly State of the Market Report for PJM: January through September*.

1 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).

SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2011, had installed generating capacity of 179,572 megawatts (MW) and more than 750 market buyers, sellers and traders of electricity[1] in a region including more than 58 million people[2] in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3] In the first nine months of 2011, PJM had total billings of $28.8 billion. As part of that market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

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



1 See <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.
2 See <http://pjm.com/about-pjm/who-we-are/company-overview.aspx>.
3 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.
4 On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint.

PJM Market Background

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.[5, 6]

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

5 See also the *2010 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
6 Analysis of 2011 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2011, see the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Conclusions

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

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

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

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

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

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

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

The MMU concludes the following for the first nine months of 2011:

Table 1-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 889 and a maximum of 1564 in the January through September period of 2011.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier test, used to test local market structure, indicate the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[7] 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

7 OATT Attachment M

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.[8]

Table 1-2 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. 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.

- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For almost every auction held, all LDAs failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.

- 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 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.

8 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.

- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and a definition of DR which permits an inferior product to substitute for capacity.

Table 1-3 The Regulation Market results were not competitive[9]

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in the first nine months of 2011.

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

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

- Market design was evaluated as flawed because the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

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

Table 1-4 The Synchronized Reserve Markets results were competitive

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

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 56 percent of the hours in the first nine months of 2011.

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

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

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

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

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about ten 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 should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The FTR Auction Markets results were competitive

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

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.

- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior in the first nine months of 2011.

- Performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.

- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[10] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[11]

10 18 CFR § 35.28(g)(3)(ii); *see also Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

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

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[12] The MMU has direct, confidential access to the FERC.[13] The MMU may also refer matters to the attention of State commissions.[14]

The MMU monitors market behavior for violations of FERC Market Rules.[15] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation,[16] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[17] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[18]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[19] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral[20] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[21] If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities, or participates as a party or provides 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 (CDG).[22] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[23]

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

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

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[28] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[29] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[30] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[31] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[32]

Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[33] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

The additional recommendation from the *2011 Quarterly State of the Market Report for PJM: January through June,* that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs, also remains an MMU recommendation. (See Section 6, "Ancillary Services", Page 154.)

Highlights

The following presents highlights of each of the sections of the *2011 Quarterly State of the Market Report for PJM: January through September*, including the new analysis that has been included in this report since the *2010 State of the Market Report for PJM*:

Section 2, Energy Market, Part 1

- Average offered supply increased by 11,535, or 7.4 percent, from 156,259 MW in the third quarter of 2010 to 167,794 MW in the third quarter of 2011. The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 3,639 MW of nameplate capacity to PJM in 2011. This includes three large plants (over 550 MW) that have started generating in PJM since January 1, 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011. (See Page 19.)

- The PJM system peak load for the third quarter of 2011 was 158,016 MW in the HE 1700 on July 21, 2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the third quarter of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.[34] The ATSI transmission zone accounted for 13,953 MW in the peak hour of third quarter 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load. (See Page 19 and 20.)

- PJM average real-time load in the first nine months of 2011 increased by 3.3 percent from the first nine months of 2010, from 81,068 MW to 83,762 MW. The PJM average real-time load in the first nine months of 2011 would have decreased by 1.2 percent from the first nine months of 2010, from 81,068 MW to 80,135 MW, if the ATSI transmission zone were excluded. (See Page 26 and 27.)

24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.D.
29 *Id.*
30 *Id.*
31 *Id.*
32 OATT Attachment M § VI.A.
33 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

34 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- PJM average day-ahead load, including DECs, in the first nine months of 2011 increased by 0.2 percent from the first nine months of 2010, from 92,683 MW to 92,828 MW. PJM average day-ahead load, including DECs, in the first nine months of 2011 would have been 3.8 percent lower than in the first nine months of 2010, from 92,683 MW to 89,146 MW if the ATSI transmission zone were excluded. (See Page 28.)

- PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 increased by 6.7 percent from the first nine months of 2010, from 76,455 MW to 81,593 MW. PJM average day-ahead load, excluding virtuals, in the first nine months of 2011 would have increased by 2.0 percent from the first nine months of 2010, from 76,455 MW to 78,017 MW if the ATSI transmission zone were excluded. (See Page 28.)

- PJM average real-time generation in the first nine months of 2011 increased by 3.4 percent from the first nine months of 2010, from 84,086 MW to 86,963 MW. PJM average real-time generation in the first nine months of 2011 would have decreased 0.6 percent from the first nine months of 2010, from 84,086 MW to 83,573 MW if the ATSI transmission zone were excluded. (See Page 30.)

- PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 increased by 4.0 percent from the first nine months of 2010, from 84,790 MW to 88,220 MW. The PJM average day-ahead generation, excluding virtuals, in the first nine months of 2011 would have decreased by 0.1 percent from the first nine months of 2010, from 84,790 MW to 84,691 MW if the ATSI transmission zone were excluded. (See Page 30.)

- PJM Real-Time Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 0.9 percent lower in the first nine months of 2011 than in the first nine months of 2010, $49.48 per MWh versus $49.91 per MWh. (See Page 32.)

- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2011 compared to the first nine months of 2010. The load-weighted average LMP was 1.6 percent lower in the first nine months of 2011 than in the first nine months of 2010, $48.34 per MWh versus $49.12 per MWh. (See Page 34.)

- Levels of offer capping for local market power remained low. In the first nine months of 2011, 0.9 percent of unit hours and 0.3 percent of MW were offer capped in the Real-Time Energy Market and 0.0 percent of unit hours and 0.0 percent of MW were offer capped in the Day-Ahead Energy Market. (See Page 21.)

- Of the 176 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2011, 58 (33 percent) qualified in all nine months, and 20 (11 percent) qualified in only one month of 2011. (See Page 23.)

- The overcollected portion of transmission losses decreased in the first nine months of 2011 to $502.1 million, or 43.6 percent of the total losses compared to $639.9 million or 50.8 percent of total losses in the same period in 2010. (See Page 44.)

- In the first nine months of 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 43,965 MWh compared to the same period in 2010, from 58,280 MWh in 2010 to 14,315 MWh in 2011, a 75 percent decrease. Total payments under the Economic Program decreased by $779,756, from $2,677,937 in 2010 $1,898,180 in 2011, a 29 percent decrease. (See Page 53 and 54.)

- In the first nine months of 2011, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $19.5 million, or 5.4 percent, compared to the same period in 2010, from $362 Million in 2010 to $381 Million in 2011. (See Page 54.)

Section 3, Energy Market, Part 2

- Net revenue performance was the result of capacity market prices, which declined in all LDAs except rest of RTO and energy market prices which were lower for most zones. Combustion turbine (CT) net revenues were lower in ten zones and higher in six zones, including four zones where net revenues increased by more than 20 percent. Combined Cycle (CC) net revenues were lower in eleven zones and higher in five zones, including three zones where net revenues increased by more than 20 percent. Coal Plant (CP) net revenues were lower in twelve zones and higher in four zones, including one zone where net revenues increased by more than 20 percent. (See Page 60 and 61.)

- There were no scarcity pricing events in the first nine months of 2011 under PJM's current Emergency Action based scarcity pricing rules. (See Page 86.)

- Operating reserve charges increased $83,751,028, or 20.5 percent, from $408,267,759 in the first nine months of 2010, to $492,018,787 in the first nine months of 2011. Reliability credits decreased $7,716,442, or 9.4 percent, in the first nine months of 2011 compared to the first nine months of 2010, and deviation credits increased $263,011,867, or 184.3 percent. (See Page 87.)

- Reliability charges were $74,733,573, 15.6 percent of all balancing operating reserve charges for the first nine months 2011, a decrease of $7,801,659 or 9.4 percent from the first nine months of 2010. Deviation charges were $405,744,328, or 84.4 percent in the first nine months of 2011, an increase of $262,622,763, or 183.5 percent from the first nine months of 2010. (See Page 88.)

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 29.7 percent of total operating reserve credits in the first nine months of 2011, compared to 36.4 percent in the first nine months of 2010. In the first nine months of 2011, the top generation owner received 22.7 percent of the total operating reserve credits paid. (See Page 94.)

- The regional concentration of balancing operating reserves for the first nine months of 2011 is higher than the first nine months of 2010, with 28.7 percent of the credits paid to units operating in the Dominion zone, 21.8 percent in the PSEG zone, and 10.1 percent in the AEP zone. (See Page 93.)

- In the first nine months of 2011, coal units provided 48.2 percent, nuclear units 33.8 percent and gas units 13.8 percent of total generation. Compared to the first nine months of 2010, generation from coal units decreased 0.3 percent, and generation from nuclear units increased 1.5 percent, while generation from natural gas units increased 24.4 percent, and generation from oil units decreased 29.5 percent. (See Page 71.)

- At the end of September 2011, 86,864 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 since the June 1, 2011, ATSI integration. Wind projects account for approximately 39,459 MW of capacity, 45.4 percent of the capacity in the queues and combined-cycle projects account for 26,785 MW, 30.8 percent, of the capacity in the queues. (See Page 72.)

- Three large plants (over 550 MW) started generating in PJM since January 1, 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, and Longview Power in the APS zone. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,639 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI zone additions), the most since 2002. (See Page 72.)

Section 4, Interchange Transactions

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated. (See Page 114.)

- Real-time net exports decreased to -7,113.9 GWh during the first nine months of 2011 from -7,411.9 GWh during the first nine months of 2010. Day-ahead net imports were 9,066.0 GWh compared to net exports of -6,657.8 GWh during the first nine months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first nine months of 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. (See Page 108 and 110.)

- The direction of power flows was not consistent with real-time energy market price differences in 56 percent of hours at the border between PJM and MISO and in 47 percent of hours at the border between PJM and NYISO during the first nine months of 2011. (See Page 115 and 116.)

- During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh or 8.3 percent, an increase from 4.8 percent during the first nine months of 2010 and 5.2 percent for the calendar year 2010. This difference is system inadvertent. (See Page 119.)

- PJM initiated 58 TLRs during the first nine months of 2011, a reduction from the 96 TLRs in the first nine months of 2010. (See Page 121.)

- The average daily volume of up-to congestion bids increased from 376 bids per day, for the period between March 1, 2009 through May 14, 2010, to 762 bids per day for the period between May 15, 2010 through September 16, 2010, to 1,987 bids per day for the period between September 17, 2010 through September 30, 2011. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids. (See Page 121 through 123.)

- Total uncollected congestion charges during the first nine months of 2011 were $11,942, compared to $2.9 million for the first nine months of 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. (See Page 128.)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.3 million during the first nine months of 2011, an increase from $290,515 in the first nine months of 2010. (See Page 104.)

Section 5, Capacity Markets

- The 2012/2013 RPM Second Incremental Auction and the 2013/2014 First Incremental Auction were run in the third quarter of 2011. In the 2012/2013 RPM Second Incremental Auction, the RTO resource clearing price was $13.01 per MW-day, and the EMAAC resource clearing price was $48.91 per MW-day. In the 2013/2014 RPM First Incremental Auction, the RTO resource clearing price was $20.00 per MW-day, the EMAAC resource clearing price was $178.85 per MW-day, and the SWMAAC resource clearing price was $54.82 per MW-day. (See Page 139.)

- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 delivery year. (See Page 135.)

- Capacity in the RPM load management programs totals 9,681.0 MW for June 1, 2011. (See Page 138.)

- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $127.05 per MW-day in 2014. (See Page 141.)

- Average PJM equivalent demand forced outage rate (EFORd) increased from 6.7 percent in the first nine months of 2010 to 7.6 percent in the first nine months of 2011. The increase in system EFORd resulted primarily from an increase in EFORd for steam units, offset by reductions in EFORd for combined cycle units and combustion turbine units. (See Page 143.)

- The PJM aggregate equivalent availability factor (EAF) decreased from 86.4 percent in the first nine months of 2010 to 84.8 percent in the first nine months of 2011. The equivalent maintenance outage factor (EMOF) remained constant at 2.8 percent in the first nine months of 2010 and the first nine months of 2011, the equivalent planned outage factor (EPOF) increased from 6.2 percent from the first nine months of 2010 to 7.2 percent in the first nine months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.6 percent in the first nine months of 2010 to 5.2 percent in the first nine months of 2011. (See Page 142.)

Section 6, Ancillary Services

- The load weighted average Regulation Market clearing price, including opportunity cost, for the first nine months of 2011 was $17.03 per MW.[35] This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2011 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010. (See Page 160.)

35 The term “load weighted” in the Regulation Market refers to regulation MW weighted.

- The load weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010.[36] The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The load weighted average Synchronized Reserve Market clearing price was 73 percent of the load weighted average total cost per MW of synchronized reserve in the first nine months of 2011, up from 70 percent in the same time period of 2010. (See Page 168.)

- The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. (See Page 170.)

- Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone. (See Page 171.)

Section 7, Congestion

- Congestion costs in the first nine months of 2011 decreased by 25.7 percent over congestion costs in the first nine months of 2010 (Table 7-2). (See Page 177.)

- Net balancing congestion costs were -$192.9 million in the first nine months of 2011 and -$169.8 million in the first nine months of 2010. Negative balancing congestion costs indicate that the congestion payments in the Day-Ahead Market exceeded congestion payments in the Real-Time Market. (See Page 179.)

- Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was the most congested zone in the first nine months of 2011, despite having, on average, negative congestion components in zonal LMPs. Measured in these terms, ComEd accounted for 22.2 percent of the total congestion cost (Table 7-21). In the first nine months of 2010, AP was the most congested zone, accounting for 19.8 percent of the total net congestion cost (Table 7-22.)[37] (See Page 190.)

- Monthly congestion costs in the first nine months of 2011 were lower than monthly congestion costs in the same period in 2010, with the exception of January and March (Table 7-3). (See Page 177.)

- PJM backbone transmission projects are a subset of significant baseline transmission upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. (See Page 176.)

  On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) that the MAPP in-service date of 2015 was moved to 2019-2021, and advised PHI to sustain efforts needed to allow the MAPP project to be resumed.

  In October 2011, the Rapid Response Team for Transmission, a federal interagency team led by the White House Council on Environmental Quality, included the Susquehanna-Roseland power line project in its list of seven transmission line projects for rapid review and permit process.

Section 8, Financial Transmission Rights and Auction Revenue Rights

- On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint. Network Service users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period. (See Page 196.)

- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2011 to 2012 planning period increased by 84 percent from 580,753 MW to 1,067,014

36 The term “load weighted” in the Synchronized Reserve Market refers to synchronized reserve MW weighted.

37 Since the *2008 State of the Market Report* the MMU has provided load congestion payments and generation congestion credits calculated as constraint specific net congestion costs by organization by zone. Load congestion payments and generation congestion credits are calculated by constraint for each zone. Within each zone, where constraint specific congestion payments and credits are of the same sign, the payments and credits are netted by organization within the zone. For a specific constraint, this results in an organization being assigned either net generation congestion credits or net load congestion charges within a zone. All net generation credits and net congestion payments are summed across organizations within each zone to determine the total congestion generation credits, total congestion load charges and total net congestion charges by zone. These results are used to calculate system-wide total congestion generation credits and total congestion load charges.

MW compared to the first four months of the 2010 to 2011 planning period. (See Page 198.)

- FTRs were paid at 84.9 percent of the target allocation level for the full 2010 to 2011 planning period and 90.9 percent for the first four months of the 2011 to 2012 planning period. (See Page 206.)

- FTRs were profitable overall and were profitable for both physical and financial entities in the first nine months of 2011. Total FTR profits were $363.7 million for physical entities and $147.2 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities. (See Page 205.)

Total Price of Wholesale Power

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

Table 1-7 shows that Energy, Capacity and Transmission Service Charges represent the three largest components of the total price per MWh of wholesale power, contributing 96.1 percent of the total price per MWh in the first nine months of 2011. The cost of energy was 74.3 percent of the total price per MWh in 2011, the cost of capacity was 15.3 percent and the cost of transmission service was 6.5 percent in the first nine months of 2011.

The total per MWh price of wholesale power for the first nine months of 2011, $66.58, was 2.8 percent lower than total per MWh price of wholesale power for the first nine months of 2010, $67.83. This decrease in the total price per MWh is largely attributable to the 13.0 percent decrease which was the result of a reduction in the capacity price between 2010 and 2011.

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

Components of Total Price

- The Load Weighted 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 Charge 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 (AC2) 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 Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[43]

- 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.[44]

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 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
44 OATT Schedule 1A.

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[45]
- The Black Start component is the average cost per MWh of black start service.[46]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[47]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[48]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[49]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[50]

Table 1-7 Total price per MWh by category and total revenues by category: January through September of 2010 and 2011 (See 2010 SOM, Table 1-7)

Category	2010 (Jan-Sep) $/MWh	2011 (Jan-Sep) $/MWh	Percent Change $/MWh	2010 (Jan-Sep) Percent	2011 (Jan-Sep) Percent
Energy	$49.91	$49.47	(0.9%)	73.6%	74.3%
Capacity	$11.71	$10.19	(13.0%)	17.3%	15.3%
Transmission Service Charges	$3.93	$4.30	9.4%	5.8%	6.5%
Operating Reserves (Uplift)	$0.76	$0.90	18.2%	1.1%	1.3%
PJM Administrative Fees	$0.37	$0.38	2.2%	0.6%	0.6%
Reactive	$0.36	$0.38	7.3%	0.5%	0.6%
Regulation	$0.37	$0.36	(5.3%)	0.6%	0.5%
Transmission Enhancement Cost Recovery	$0.18	$0.28	55.9%	0.3%	0.4%
Synchronized Reserves	$0.06	$0.09	54.1%	0.1%	0.1%
Transmssion Owner (Schedule 1A)	$0.09	$0.09	1.6%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.07	402.8%	0.0%	0.1%
Black Start	$0.02	$0.02	21.9%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(8.2%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(3.2%)	0.0%	0.0%
Load Response	$0.01	$0.01	(11.0%)	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	25.9%	0.0%	0.0%
Total	$67.83	$66.58	(1.8%)	100.0%	100.0%

45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6..
46 OATT Schedule 6A.
47 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
48 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
49 OA Schedule 1 § 3.6.
50 OA Schedule 1 § 5.3b.