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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

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

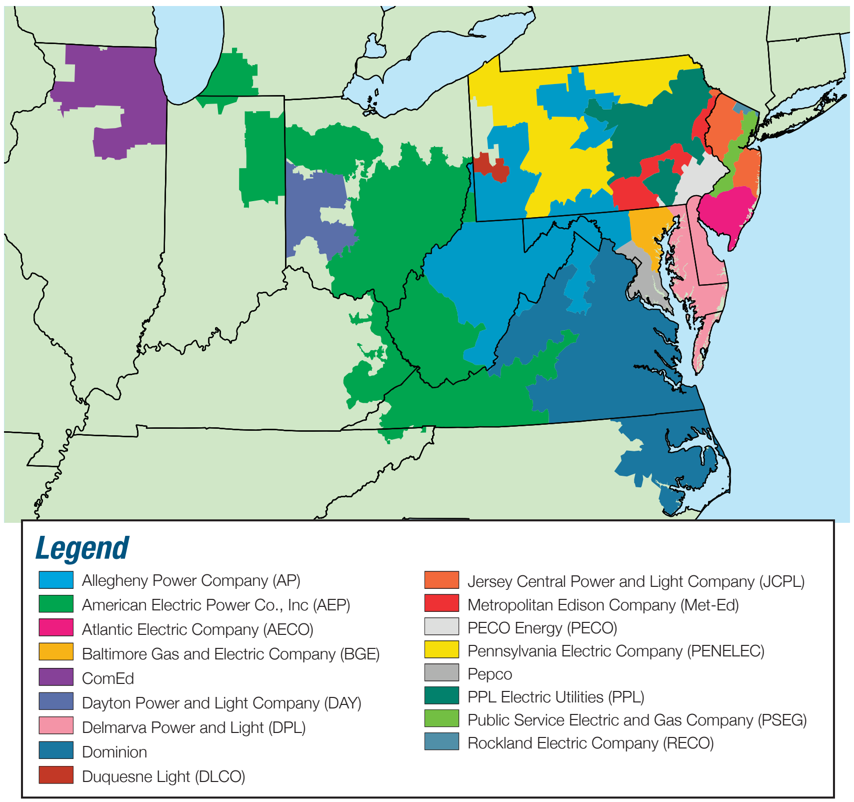
1 OATT Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC 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 March 31, 2011, had installed generating capacity of 166,292 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 54 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)[1]. In the first three months of 2011, PJM had total billings of $9.58 billion. As part of that 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 17 control zones



1 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.

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.[2, 3]

2 See also the *2010 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 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. 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, 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 three 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. Unit markup is an important measure of participant behavior. Unit markup measures the relationship between the offer of a unit and the marginal cost of a unit. The higher the unit markup, the less competitive the offer.

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. Markup and net revenue are the most relevant measures of market performance. Markup measures the relationship between the marginal costs of marginal units and the marginal offers of marginal units and therefore the market clearing prices in the market. The higher the performance markup, the less competitive the market. Net revenue measures the revenues available from markets in excess of marginal costs which are available to cover all other unit costs.

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

The MMU concludes the following for the first three months of 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 three months of 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1202 with a minimum of 1058 and a maximum of 1439 in January through March 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, indicates 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.

- 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 the first three months of 2011, the markup component of the PJM real-time, load-weighted, average LMP was $0.48 per MWh, or 1.0 percent.

- 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.

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, 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 and the submitted sell offer exceeded the defined offer cap.

- 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, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

Table 1-3 The Regulation Market results were not competitive[4]

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 94 percent of the hours.

- 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,

4 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.

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

Table 1-4 The Synchronized Reserve Markets results were competitive

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

- The market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand.

- Participant behavior was evaluated as competitive because the market rules require 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 by offer capping those suppliers.

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 market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a very limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about five 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 quarter of 2011 and there is no limit on FTR demand in any FTR auction.

- Performance was evaluated as competitive because it reflected the interaction between participant 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.[5] These functions are interrelated and overlap. The PJM Market Monitoring Plan captures 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 potential for a Market Participant to exercise market power or violate any of the PJM or FERC Market Rules or the actual exercise of market power or violation of the PJM or FERC Market Rules; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[6, 7, 8]

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,"[9] 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 State of the Market Report for PJM: January through March*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Highlights

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

5 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).
6 OATT Attachment M § IV.B.
7 18 CFR § 1c.2.
8 PJM Open Access Transmission Tariff (OATT) Attachment M § IV.
9 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

Section 2, Energy Market, Part 1

- Average offered supply increased by 948 MW, less than one percent, from 158,680 MW in the first three months of 2010 to 159,628 MW in the first three months of 2011. (Page 18)

- The PJM system peak load for the first three months of 2011 was 110,659 MW, which was 1,448 MW, or 1.3 percent, higher than the peak load in the first three months of 2010. (Page 18)

- PJM average real-time load in the first three months of 2011 decreased by 0.1 percent from the first three months of 2010, from 81,121 MW to 81,018 MW. PJM average day-ahead load in the first three months of 2011 decreased by 4.4 percent from the first three months of 2010, from 93,559 MW to 89,478 MW. (Page 27 and Page 28)

- PJM Real-Time Energy Market prices increased in the first three months of 2011 compared to the first three months of 2010. The load-weighted average LMP was 0.9 percent higher in the first three months of 2011 than in the first three months of 2010, $46.35 per MWh versus $45.92 per MWh. (Page 34)

- PJM Day-Ahead Energy Market prices decreased in the first three months of 2011 compared to the first three months of 2010. The load-weighted LMP was 1.3 percent lower in the first three months of 2011 than in the first three months of 2010, $47.14 per MWh versus $47.77 per MWh. (Page 39)

- Analysis of the real-time load-weighted LMP for the first three months of 2011 showed that 46.5 percent of the load-weighted LMP was the result of coal costs; 30.9 percent was the result of gas costs and 2.2 percent was the result of the cost of emission allowances. Markup was 1.0 percent of LMP, consistent with a competitive market outcome. (Page 36)

- Levels of offer capping for local market power remained low. In the first three months of 2011, 0.6 percent of unit hours and 0.2 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. (Page 20)

- In the first three months of 2011, the total MWh of load reduction under the Economic Program decreased by 5,900 MWh compared to the same period in 2010, from 8,100 MWh in 2010 to 2,100 MWh in 2011, a 74 percent decrease. Total payments under the Economic Program decreased by $176,000, from $321,600 in 2010 to $145,600 in 2010, a 55 percent decrease. (Page 60 and Page 61)

- In the first three months of 2011, total capacity payments under the Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, increased by $43 million, or 43 percent, compared to the same period in 2010, from $101 Million in 2010 to $144 Million in 2011. (Page 62)

Section 3, Energy Market, Part 2

- Net revenues were generally higher for the CT and CC technologies through the first three months of 2011 compared to the same period in 2010, while net revenues for the CP technology were generally lower. (Page 70 and Page 71)

- The increases in net revenues for the CT and CC technologies were the result of higher energy market net revenues, and, in the case of zones which cleared in the RTO LDA for the 2009/2010 delivery year, higher capacity revenues. (Page 67 and Page 68)

- There were no scarcity pricing events in the first three months of 2011 under PJM's current Emergency Action based Scarcity Pricing Rules. (Page 65)

- Operating reserve charges increased $16,402,426, 14.9 percent, from $126,776,024 in the first three months of 2011 compared $110,373,599 in the first three months of 2010. Reliability credits increased $7,922,157, or 49.7 percent, in the first three months of 2011 compared to the first three months of 2010, and deviation credits increased $9,248,673, or 19.5 percent. (Page 91 through Page 93)

- Reliability charges were $23,854,871, 29.6 percent of all balancing operating reserve charges for the first three months 2011, and deviation charges were $56,624,124, 70.4 percent. (Page 92)

- RTO and Eastern deviation balancing operating reserve rates spiked during the fourth week of January 2011, reaching $9.1035/MWh and $2.2142/MWh as a result of the low temperatures, increased natural gas prices at Transco and Texas Eastern pipeline pricing points, and increased dispatch of units for operating reserves in the eastern regions of PJM. The price for natural gas at these pipeline pricing points on the peak day averaged $16.39/MMBtu, while the average price for pricing points on all other pipelines averaged $4.88. The fourth week of 2011, 7.8 percent of the days, accounted for 29.1 percent, $23,433,940, of balancing operating reserves for the first three months of 2011. (Page 94)

- Operating reserve credits for dispatchable transactions, which are a subset of pool-scheduled spot market import transactions, or balancing transaction operating reserve credits, for the months January through March 2011, were $1,273,235. The year with the next highest first quarter total balancing transaction operating reserve credits was in 2002, when credits were $98,065. (Page 96)

- 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 50.3 percent of total operating reserve credits in the first three months of 2011, compared to 47.5 percent in the first three months 2010. In the first three months of 2011, the top generation owner received 47.9 percent of the total operating reserve credits paid. (Page 101)

- The regional concentration of balancing operating reserves also remains high for the first three months of 2011, with 44.5 percent of the credits being paid to units operating in the PSEG zone, 18.6 percent in Dominion, and 7.2 percent in the AEP zone. (Page 101)

- In the first three months of 2011, coal units provided 47.7 percent, nuclear units 35.7 percent and gas units 12.0 percent of total generation. Compared to the first three months of 2010, generation from coal units decreased 11.2 percent, and generation from nuclear units increased 2.8 percent. Generation from natural gas units increased 69.0 percent, and generation from oil units increased 101.7 percent. (Page 77)

- At the end of March 2011, 75,737 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 167,000 MW in 2011. Wind projects accounted for approximately 37,579 MW of capacity, 49.6 percent of the capacity in the queues, and combined-cycle projects account for 15,763 MW, 20.8 percent, of the capacity in the queues. (Page 79)

Section 4, Interchange Transactions

- Real-time net exports decreased to -802.0 GWh during the first three months of 2011 from -842.3 GWh during the first three months of 2010. During the first three months of 2011, there were day-ahead net imports of 3,813.9 GWh compared to net exports of -780.9 GWh during the first three months of 2010. (Page 113 and Page 114)

- The direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences in 62 percent of hours between PJM and the Midwest ISO and in 47 percent of hours between PJM and NYISO during the first three months of 2011. (Page 117 and Page 118)

- During the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh for a difference of 137 GWh or 185.1 percent (21.4 percent during the first three months of 2010 and 5.2 percent for the calendar year 2010). This difference is system inadvertent. (Page 121)

- PJM initiated the same number of TLRs during the first three months of 2011 as during the first three months of 2010 (13 TLRs). (Page 123)

- 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, 2011, to 1,338 bids per day for the period between September 17, 2010 through March 31, 2011. A significant increase in bid volume occurred following the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids. (Page 124 and Page 125)

- Total uncollected congestion charges during the first three months of 2011 were $4,669, compared to $978,756 for the first three 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. (Page 128)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were $1.1 million during the first three months of 2011, an increase from $92,742 in the first three months of 2010. (Page 110)

Section 5, Capacity Markets

- The 2011/2012 Third Incremental Auction was run in the first quarter of 2011. The RTO resource clearing price in the 2011/2012 RPM Third Incremental Auction was $5.00 per MW-day, a decrease of $40.00 per MW-day from the 2010/2011 RPM Third Incremental Auction resource clearing price. (Page 141)

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

- Capacity in the RPM load management programs totals 10,810.1 MW for June 1, 2011. (Page 137 and 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 $100.26 per MW-day in 2013. (Page 143)

- The average PJM equivalent demand forced outage rate (EFORd) increased from 6.9 percent in the first three months of 2010 to 8.0 percent in the first three months of 2011. (Page 145)

- The PJM aggregate equivalent availability factor (EAF) decreased from 87.4 percent in the first three months of 2010 to 85.9 percent in the first three months of 2011. The equivalent maintenance outage factor (EMOF) increased from 2.3 percent in the first three months of 2010 to 2.7 percent in the first three months of 2011, the equivalent planned outage factor (EPOF) remained constant at 6.3 percent from the first three months of 2010 to the first three months of 2011, and the equivalent forced outage factor (EFOF) increased from 4.0 percent in the first three months of 2010 to 5.2 percent in the first three months of 2011. (Page 145)

Section 6, Ancillary Services

- The load weighted regulation market clearing price for the first three months of 2011 was $11.51, 35 percent lower than the $17.84 price for the first three months of 2010. Regulation total costs per MW for the first three months of 2011 were $24.83, a decrease of 19 percent from the $30.69 total cost in the first three months of 2010. For the first three months of 2011 the total cost of regulation per MW was 116 percent higher than the market clearing price. For the first three months of 2010 the total cost of regulation was 72 percent higher than the market clearing price. (Page 161)

- Total self-scheduled regulation MW in the first three months of 2011 was 18 percent of all regulation, an increase from 16 percent in the first three months of 2010. The supply of eligible regulation increased by four percent in the first three months of 2011 relative to the same period of 2010. (Page 159)

- Of the LSEs' obligation to provide regulation during the first three months of 2011, 79 percent was purchased in the spot market, 18 percent was self scheduled, and 3 percent was purchased bilaterally. (Page 159)

- The load weighted synchronized reserve market price in the first three months of 2011 was $10.96 per MWh, $3.94 higher than the price during the first three months of 2010. The total cost of synchronized reserves per MWh during the first three months of 2011 was $13.22, a 38 percent increase over the cost of synchronized reserves ($9.54) during the same period of 2010. The cost to price ratio of synchronized reserve during the first three months of 2011 was 120 percent, a decrease from the cost to price ratio of 136 percent in the first three months of 2010. (Page 168)

- In December of 2010 PJM Market Operations changed the Tier 1 synchronized reserve transfer capacity across the AP South interface from 15 percent of available Tier 1 to 5 percent.[10] Less Tier 1 synchronized reserve available means more Tier 2 synchronized reserve is required in the Mid-Atlantic Subzone in order to satisfy the 1,300 MW requirement. This has resulted in significant increases in scheduled Tier 2 synchronized reserves in the Mid-Atlantic Subzone Synchronized Reserve market. (Page 164)

- The load weighted price of DASR in the first three months of 2011 was $0.02 per MW. In the first three months of 2010, the load weighted price of DASR was $0.05 per MW. (Page 169)

- Black start zonal charges in the first three months of 2011 ranged from $0.03 per MW in DLCO zone to $0.61 per MW in PSEG zone. (Page 170)

Section 7, Congestion

- Congestion costs in the first three months of 2011 increased by 4.6 percent over congestion costs in the first three months of 2010 (Table 7-2). Most of the increase was in the Day-Ahead Market. (Page 174)

- Net balancing congestion costs were -$46.0 million in the first three months of 2011 and -$46.9 million in the first three months of 2010. Negative balancing congestion costs indicates that the congestion payments in the Day-Ahead market exceeded congestion payments in the Real-Time market. (Page 176)

- In the first three months of 2011, AP was the most congested zone. AP accounted for nearly 18 percent of the total congestion cost (Table 7-17). In the first three months of 2010, Dominion was the most congested zone, accounting for nearly 20 percent of the total congestion cost. (Page 187 and Page 188)

- January and March congestion costs were significantly higher compared to 2010 (10.7 percent and 120.8 percent). February congestion costs were substantially lower compared to 2010 (-30.4 percent). (Table 7-3). (Page 175)

- PJM backbone projects are a subset of significant baseline 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. (Page 173)

  On February 28, 2011, PJM announced that the Board decided to hold the Potomac – Appalachian Transmission Highline (PATH) project in abeyance in its 2011 Regional Transmission Expansion Plan (RTEP), but did not direct the sponsoring Transmission Owners to cancel or abandon the PATH project. (Page 173)

10 See the *2010 State of the Market Report for PJM,* Section 6, "Ancillary Service Markets", p. 452.

On February 28, 2011, American Electric Power and FirstEnergy Corp., the sponsoring Transmission Owners, announced that they would file to withdraw their applications for state regulatory approval of the PATH. (Page 173)

Section 8, Financial Transmission Rights and Auction Revenue Rights

- FTRs were paid at 87.9 percent of the target allocation level for the 2010 to 2011 planning period through March 31, 2011. (Page 231 and Page 232)
- ARRs reassigned for network load changes in the first ten months of the 2010 to 2011 planning period were 48,637 MW, an increase of 153 percent from the full 12-month 2009 to 2010 planning period. (Page 233)
- There were no transactions in the secondary bilateral FTR obligation market for the first three months of 2011. (Page 228)
- FTRs were profitable overall and were profitable for both physical entities and financial entities in the first three months of 2011. Total FTR profits were $174.9 million for physical entities and $57.0 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities. (Page 232)

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 March 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 96.3 percent of the total price per MWh in the first quarter of 2011. The cost of energy was 70.6 percent of the total price per MWh in 2011, the cost of capacity was 19.2 percent and the cost of transmission service was 6.6 percent in the first quarter of 2011.

The total per MWh price of wholesale power for the first quarter of 2011, $65.68, was 4.5 percent higher than total per MWh price of wholesale power for the first quarter of 2010, $62.86. This increase in the total price per MWh is largely attributable to the 14.6 percent increase in the price of capacity and the 11.7 percent increase in the price of transmission.

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.[11]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[12]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[13]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[14]
- 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.

11 OATT §§ 13.7, 14.5, 27A & 34.
12 OA Schedules 1 §§ 3.2.3 & 3.3.3.
13 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
14 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

- 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.[15]

- 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.[16]

- 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.[17]

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[18]

- The Black Start component is the average cost per MWh of black start service.[19]

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[20]

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[21]

- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[22]

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[23]

15 OATT Schedule 12.
16 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
17 OATT Schedule 1A.
18 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6..
19 OATT Schedule 6A.
20 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
21 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
22 OA Schedule 1 § 3.6.
23 OA Schedule 1 § 5.3b.

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

Category	Totals ($ Millions) 2010 (Jan-Mar)	Totals ($ Millions) 2011 (Jan-Mar)	Percent Change Totals	2010 (Jan-Mar) $/MWh	2011 (Jan-Mar) $/MWh	Percent Change $/MWh	2010 (Jan-Mar) Percent	2011 (Jan-Mar) Percent	Percent Change in Proportions
Energy	$8,042.41	$8,107.95	0.8%	$45.92	$46.35	0.9%	73.1%	70.6%	(3.4%)
Capacity	$1,926.40	$2,204.37	14.4%	$11.00	$12.60	14.6%	17.5%	19.2%	9.7%
Transmission Service Charges	$677.56	$755.81	11.5%	$3.87	$4.32	11.7%	6.2%	6.6%	6.9%
Operating Reserves (Uplift)	$108.98	$126.30	15.9%	$0.68	$0.84	24.5%	1.1%	1.3%	19.2%
Reactive	$61.53	$68.09	10.7%	$0.35	$0.39	10.8%	0.6%	0.6%	6.0%
PJM Administrative Fees	$65.75	$57.36	(12.8%)	$0.38	$0.33	(12.7%)	0.6%	0.5%	(16.4%)
Transmission Enhancement Cost Recovery	$21.61	$51.94	140.3%	$0.12	$0.30	140.6%	0.2%	0.5%	130.3%
Regulation	$60.33	$47.62	(21.1%)	$0.34	$0.27	(21.0%)	0.5%	0.4%	(24.4%)
Synchronized Reserves	$9.50	$21.04	121.4%	$0.05	$0.12	121.6%	0.1%	0.2%	112.1%
Transmssion Owner (Schedule 1A)	$14.80	$16.22	9.6%	$0.08	$0.09	9.7%	0.1%	0.1%	5.0%
NERC/RFC	$3.53	$3.38	(4.1%)	$0.02	$0.02	(3.9%)	0.0%	0.0%	(8.1%)
Black Start	$2.67	$3.04	13.8%	$0.02	$0.02	14.0%	0.0%	0.0%	9.1%
RTO Startup and Expansion	$2.27	$2.27	0.1%	$0.01	$0.01	0.2%	0.0%	0.0%	(4.1%)
Load Response	$1.29	$1.22	(5.2%)	$0.01	$0.01	(5.0%)	0.0%	0.0%	(9.1%)
Transmission Facility Charges	$0.34	$0.37	10.6%	$0.00	$0.00	10.7%	0.0%	0.0%	6.0%
Day Ahead Scheduling Reserve (DASR)	$0.58	$0.24	(59.4%)	$0.00	$0.00	(59.4%)	0.0%	0.0%	(61.1%)
Total	$10,999.56	$11,467.23	4.3%	$62.86	$65.68	4.5%	100.0%	100.0%	0.0%