Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

5.16.2011

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 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).

TABLE OF CONTENTS

TABLES

SECTION 3 - ENERGY MARKET, PART 2 63

SECTION 4 - INTERCHANGE TRANSACTIONS 105

SECTION 5 – CAPACITY MARKET 131

SECTION 6 - ANCILLARY SERVICE MARKETS 151

SECTION 7 – CONGESTION 171

FIGURES

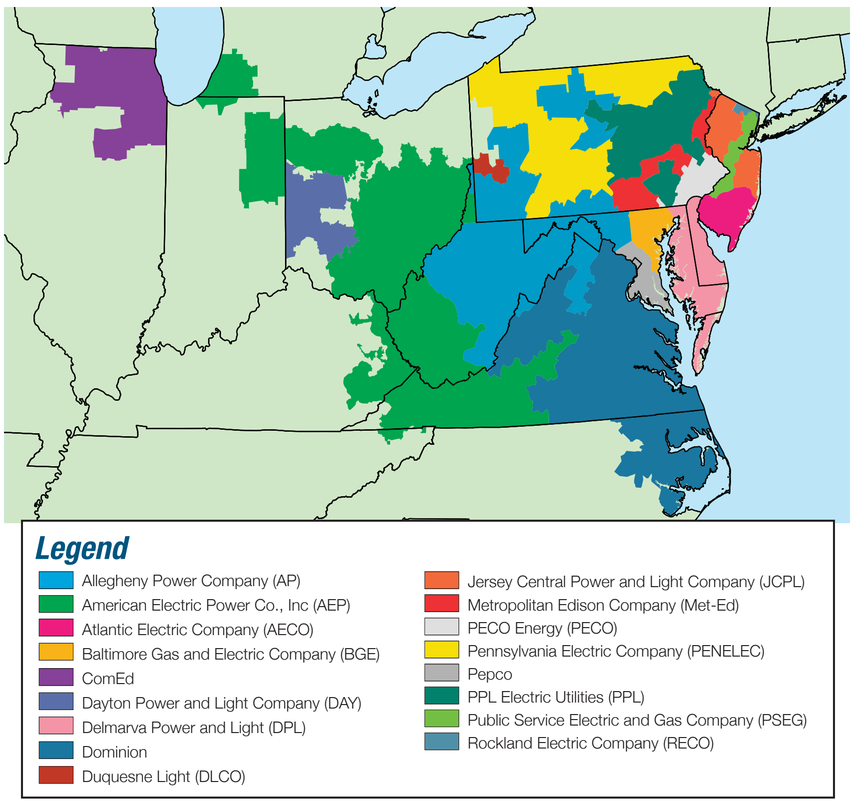
SECTION 6 - ANCILLARY SERVICE MARKETS 151

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS 223

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%

SECTION 2 – ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through March of 2011, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2011.

Table 2-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 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.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM

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

2 OATT Attachment M

Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Highlights

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

Summary Recommendations

- 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.

Overview

Market Structure

- **Supply.** During the first three months of 2011, the PJM Energy Market received an hourly average of 159,628 MWh in day-ahead supply offers including hydroelectric generation, 948 MWh higher than the first three months of 2010 average daily offered supply of 158,680 MWh.[4]

- **Demand.** The PJM system peak load for the first three months of 2011 was 110,659 MW in the hour ended 800 EPT on January 24, 2011, which was 1,448 MW, or 1.3 percent, higher than the PJM peak load

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

4 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

for the first three months of 2010, which was 109,210 MW in the hour ended 1900 EPT on January 4, 2010.[5]

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first three months of 2011. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours decreased from 0.2 percent in 2010 to 0.0 percent in the first three months of 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.6 percent in the first three months of 2011.

- **Local Market Structure.** In the first three months of 2011, the AECO, AEP, AP, ComEd, Dominion, DPL, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.[6]

5 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).

6 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

Market Performance: Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP in the first three months of 2011 was $0.48 per MWh, or 1.0 percent. Coal steam units contributed $0.24 to the total markup component of LMP. Combustion turbine units that use natural gas as their primary fuel source contributed $0.05 to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.20 to the total markup component of LMP. During the same period, the markup was $1.28 per MWh during peak hours and -$0.38 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first three months of 2011 was -$0.98 per MWh, or -2.1 percent. Coal steam units contributed -$0.77 to the total markup component of LMP. Natural gas steam units contributed -$0.21 to the total markup component of LMP. The markup was -$0.46 per MWh during peak hours and -$1.51 per MWh during off-peak hours.

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

- **Load.** On average, PJM real-time load decreased in the first three months of 2011 by 0.1 percent from the first three months of 2010, from 81,121 MW to 81,018 MW. PJM day-ahead load decreased in the first three months of 2011 by 4.4 percent from the first three months of 2010, from 93,559 MW to 89,478 MW.

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

  PJM Real-Time Energy Market prices increased in the first three months of 2011 compared to the first three months of 2010. The system simple average LMP was 1.4 percent higher in the first three months of 2011 than in the first three months of 2010, $44.76 per MWh versus $44.13 per MWh. The load-weighted 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.

  The real-time, fuel cost adjusted, load-weighted, average LMP was 7.0 percent lower in the first three months of 2011 than the real-time, load weighted LMP in the first three months of 2010 , $42.73 per MWh versus $45.92 per MWh.[7] In other words, if fuel costs in the first three months of 2011 had been the same as they were in the first three months of 2010, the load-weighted LMP of the first three months of 2011 would have been 7.8 percent lower, $42.73 per MWh, than the actual $46.35 per MWh, and 7.0 percent lower than the load-weighted average LMP for the first three months of 2010. Higher cost of coal and oil contributed to upward pressure on LMP in the first three months of 2011 compared to the first three months of 2010.

  PJM Day-Ahead Energy Market prices decreased in the first three months of 2011 compared to the first three months of 2010. The system simple average LMP was 1.2 percent lower in the first three months of 2011 than in the first three months of 2010, $45.60 per MWh versus $46.13 per MWh. 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.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first three months of 2011, 10.1 percent of real-time load was supplied by bilateral contracts, 28.7 percent by spot market purchases and 61.2 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.7 percentage points; reliance on spot supply increased by 8.4 percentage points; and reliance on self-supply decreased by 6.8 percentage points in 2011.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

  If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior.

  There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

- **Demand-Side Response Activity.** In the first three months of 2011, in the Economic Program, participation decreased compared to the same period in 2010. Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2010. Participation levels since calendar year 2008 have generally been lower compared to prior years due to a number

7 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

of factors, including lower price levels, lower load levels and improved measurement and verification. In 2010, participation showed strong growth through the summer period as price levels and load levels increased. Through the first three months of 2011, there were relatively few high load days and limited hours of sufficiently high LMPs for economic load reduction. On the peak load day for the period January through March 2011 (January 24, 2011), there were 2,445.2 MW registered in the Economic Load Response Program.

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. The Demand Response Subzonal Dispatch Task Force (DRSDTF) was established at the Markets Reliability Committee (MRC) on February 16, 2011 in response to stakeholders' request for clarity on potential future subzonal event deployments and the implications for event performance calculations. The DRSDTF was dissolved at the April 27, 2011, MRC meeting, and its responsibilities were transferred to the newly established Demand Response Subcommittee (DRS).

Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to participants in PJM demand side programs. In the first three months of 2011, Economic Program revenues decreased by $176,000 or 55 percent compared to the same period in 2010, from $321,600 to $145,600 while Load Management (LM) Program revenues increased by $43 million or 43 percent, from $101 million to $144 million. Through the first three months of 2011, Synchronized Reserve credits increased by $1.1 million compared to the same period in 2010, from $1.2 million in 2010 to $2.3 million in 2011. In the first three months of 2010 and 2011, since there were no Load Management Events, there were no emergency energy revenues.

Conclusion

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

Aggregate hourly supply offered increased by about 948 MWh in the first three months of 2011 compared to the first three months of 2010, while aggregate peak load increased by 1,448 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. Average load in the first three months of 2011 decreased from the same period in 2010, falling from 81,121 MW to 81,018 MW. Market concentration levels remained moderate and average markup was slightly positive. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

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

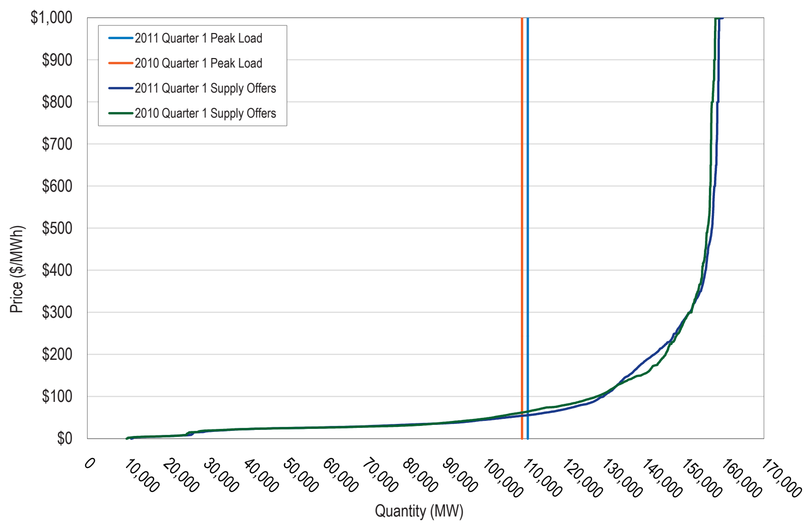
The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required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

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2011.

Market Structure

Supply

Figure 2-1 Average PJM day-ahead aggregate supply curves: January through March, 2010 and 2011 (See 2010 SOM, Figure 2-1)



8 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

Table 2-2 Frequency distribution of unit offer prices: January through March 2011 (See 2010 SOM, Table 2-3)

Range	All Offers	Pool-Scheduled Share of All Offers	Self-Scheduled Share of All Offers
($200) - $0	9.5%	21.2%	78.8%
$0 - $200	60.8%	88.6%	11.4%
$200 - $400	19.8%	98.7%	1.3%
$400 - $600	5.2%	98.2%	1.8%
$600 - $800	1.1%	91.1%	8.9%
$800 - $1,000	3.6%	92.1%	7.9%

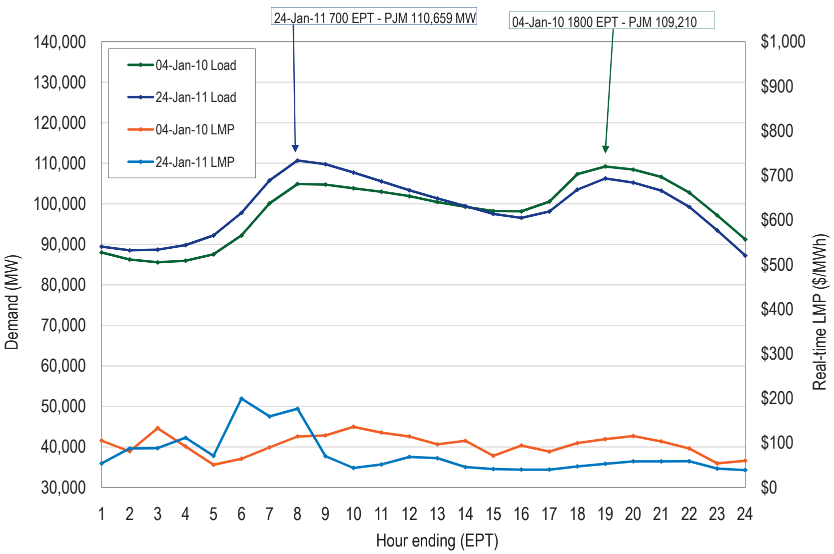
Demand

Table 2-3 Actual PJM footprint peak loads: January through March of 2003 to 2011 (See 2010 SOM, Table 2-4)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Thu, January 23	19	54,670	NA	NA
2004	Mon, January 26	19	53,620	(1,050)	(1.9%)
2005	Tue, January 18	19	96,362	42,742	79.7%
2006	Mon, February 13	20	100,065	3,703	3.8%
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%

Figure 2-2 Actual PJM footprint peak loads: January through March of 2003 to 2011 (See 2010 SOM, Figure 2-2)

Figure 2-3 PJM first quarter peak-load comparison: Monday, January 24, 2011, and Monday, January 4, 2010 (See 2010 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

Table 2-4 PJM hourly Energy Market HHI: January through March 2011[9] (See 2010 SOM, Table 2-5)

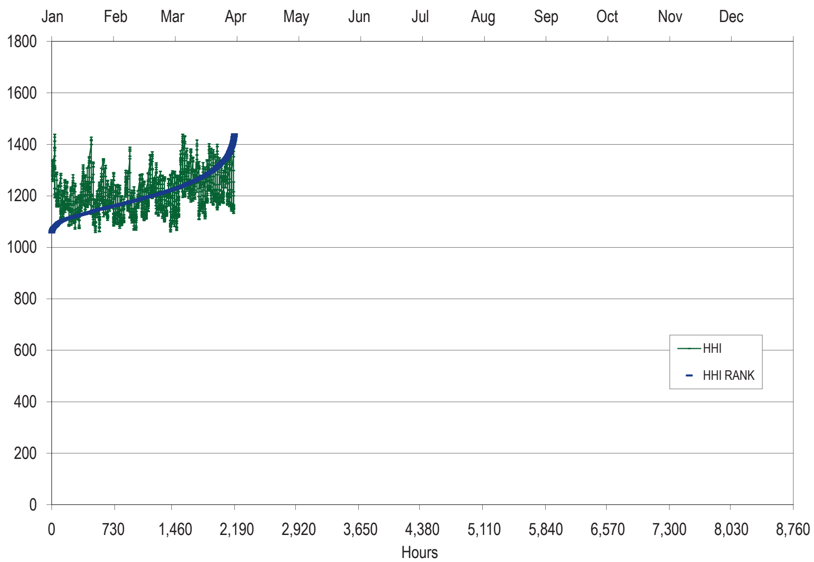
	Hourly Market HHI
Average	1202
Minimum	1058
Maximum	1439
Highest market share (One hour)	28%
Highest market share (All hours)	21%
# Hours	2,159
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-5 PJM hourly Energy Market HHI (By segment): January through March 2011 (See 2010 SOM, Table 2-6)

	Minimum	Average	Maximum
Base	1079	1224	1441
Intermediate	933	2162	6885
Peak	1084	7002	10000

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

Figure 2-4 PJM hourly Energy Market HHI: January through March 2011 (See 2010 SOM, Figure 2-4)



Local Market Structure and Offer Capping

Table 2-6 Annual offer-capping statistics: Calendar years 2007 through March 2011 (See 2010 SOM, Table 2-7)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.6%	0.2%	0.0%	0.0%

Table 2-7 Real-time offer-capped unit statistics: January through March 2011 (See 2010 SOM, Table 2-8)

	2011 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	0	48
80% and < 90%	0	0	0	0	1	14
75% and < 80%	0	0	0	0	0	5
70% and < 75%	0	0	0	0	0	4
60% and < 70%	0	0	0	0	0	25
50% and < 60%	0	0	0	0	0	17
25% and < 50%	0	0	1	0	0	26
10% and < 25%	0	0	0	1	0	5

Local Market Structure

Table 2-8 Three pivotal supplier results summary for regional constraints: January through March 2011 (See 2010 SOM, Table 2-9)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	3,940	762	19%	3,659	93%
	Off Peak	1,989	236	12%	1,888	95%
AEP-DOM	Peak	582	4	1%	582	100%
	Off Peak	1,913	32	2%	1,904	100%
AP South	Peak	11,516	180	2%	11,451	99%
	Off Peak	7,936	163	2%	7,878	99%
Dominion East	Peak	240	12	5%	230	96%
	Off Peak	92	8	9%	89	97%
East	Peak	726	221	30%	636	88%
	Off Peak	155	63	41%	118	76%
West	Peak	146	87	60%	96	66%
	Off Peak	15	5	33%	14	93%

Table 2-9 Three pivotal supplier test details for regional constraints: January through March 2011 (See 2010 SOM, Table 2-10)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	288	1,858	14	2	12
	Off Peak	314	1,962	14	1	12
AEP-DOM	Peak	358	931	8	0	8
	Off Peak	367	1,297	8	0	8
AP South	Peak	393	1,044	7	0	7
	Off Peak	449	1,193	8	0	8
Dominion East	Peak	42	231	2	1	2
	Off Peak	38	391	4	1	3
East	Peak	637	4,408	16	5	11
	Off Peak	327	3,323	12	5	7
West	Peak	445	3,622	15	8	7
	Off Peak	251	3,260	13	3	10

Table 2-10 Summary of three pivotal supplier tests applied to uncommitted units for regional constraints: January through March 2011 (See 2010 SOM, Table 2-11)

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	3,940	117	3%	43	1%	37%
	Off Peak	1,989	81	4%	24	1%	30%
AEP-DOM	Peak	582	16	3%	10	2%	63%
	Off Peak	1,913	39	2%	24	1%	62%
AP South	Peak	11,516	87	1%	16	0%	18%
	Off Peak	7,936	164	2%	31	0%	19%
Dominion East	Peak	240	3	1%	0	0%	0%
	Off Peak	92	0	0%	0	0%	0%
East	Peak	726	12	2%	3	0%	25%
	Off Peak	155	1	1%	0	0%	0%
West	Peak	146	3	2%	0	0%	0%
	Off Peak	15	0	0%	0	0%	0%

Ownership of Marginal Resources

Table 2-11 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through March 2011 (See 2010 SOM, Table 2-12)

Company	Percent of Price
1	20%
2	12%
3	12%
4	11%
5	5%
6	5%
7	5%
8	3%
9	3%
Other (54 companies)	24%

Table 2-12 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through March 2011 (See 2010 SOM, Table 2-13)

Company	Percent of Price
1	11%
2	9%
3	7%
4	6%
5	6%
6	5%
7	4%
8	4%
9	4%
Other (101 companies)	44%

Fuel Type of Marginal Units

Table 2-13 Type of fuel used (By real-time marginal units): January through March 2011 (See 2010 SOM, Table 2-14)

Fuel Type	2011
Coal	74%
Gas	23%
Wind	2%

Table 2-14 Day-ahead marginal resources by type/fuel: January through March 2011 (See 2010 SOM, Table 2-15)

Type/Fuel	2011
Transaction	67%
DEC	14%
INC	9%
Coal	8%
Natural gas	2%
Price sensitive demand	0%
Oil	0%
Municipal waste	0%

Market Conduct: Markup

Real-Time Mark Up Conduct

Table 2-15 Average, real-time marginal unit markup index (By price category): January through March 2011 (See 2010 SOM, Table 2-16)

Price Category	Average Markup Index	Average Dollar Markup
Below $25	(0.14)	($3.10)
$25 to $50	(0.02)	($1.36)
$50 to $75	(0.00)	($0.51)
$75 to $100	0.05	$3.58
$100 to $125	0.22	$23.22
$125 to $150	0.15	$18.64
Above $150	0.11	$24.48

Day-Ahead Mark Up Conduct

Table 2-16 Average marginal unit markup index (By price category): January through March 2011 (See 2010 SOM, Table 2-17)

Price Category	Average Markup Index	Average Dollar Markup
Below $25	(0.13)	($3.84)
$25 to $50	(0.03)	($1.58)
$50 to $75	0.00	$0.20
$75 to $100	0.02	$1.77
$100 to $125	0.02	$2.16
$125 to $150	0.00	$0.00
Above $150	0.15	$28.20

Market Performance

Real-Time Markup

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

Table 2-17 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March 2011 (See 2010 SOM, Table 2-18)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	$0.24	51.3%
Gas	CC	$0.20	41.1%
Gas	CT	$0.05	9.5%
Gas	Diesel	($0.00)	(0.1%)
Gas	Steam	$0.01	1.6%
Interface	Interface	$0.00	0.0%
Municipal Waste	Steam	($0.00)	(0.8%)
Oil	CT	$0.00	0.7%
Oil	Diesel	($0.00)	(0.0%)
Oil	Steam	($0.02)	(4.7%)
Wind	Wind	$0.01	1.3%
Total		$0.48	100.0%

Markup Component of Real-Time System Price

Table 2-18 Monthly markup components of real-time load-weighted LMP: January through March 20110 (See 2010 SOM, Table 2-19)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.10	$1.77	$0.47
Feb	($0.16)	$0.23	($0.57)
Mar	$0.37	$1.73	($1.19)
2011	$0.48	$1.28	($0.38)

Markup Component of Real-Time Zonal Prices

Table 2-19 Average real-time zonal markup component: January through March 2011 (See 2010 SOM, Table 2-20)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$0.80	$1.91	($0.37)
AEP	($0.34)	$0.33	($1.03)
AP	($0.18)	$0.41	($0.83)
BGE	$1.21	$2.08	$0.28
ComEd	$0.46	$0.73	$0.19
DAY	($0.40)	$0.38	($1.25)
DLCO	($0.71)	($0.01)	($1.46)
Dominion	$1.31	$1.93	$0.63
DPL	$0.82	$1.87	($0.27)
JCPL	$0.85	$2.33	($0.76)
Met-Ed	$0.76	$1.83	($0.41)
PECO	$0.85	$2.02	($0.41)
PENELEC	($0.04)	$0.66	($0.83)
Pepco	$1.32	$2.08	$0.44
PPL	$0.80	$2.01	($0.53)
PSEG	$0.66	$2.40	($1.27)
RECO	$1.42	$1.57	$1.22

Markup by Real-Time System Price Levels

Table 2-20 Average real-time markup component (By price category): January through March 2011 (See 2010 SOM, Table 2-21)

	Average Markup Component	Frequency
Below $20	($4.28)	0.5%
$20 to $40	($2.10)	58.7%
$40 to $60	($0.38)	28.6%
$60 to $80	$7.55	5.6%
$80 to $100	$15.39	2.4%
$100 to $120	$18.17	1.7%
$120 to $140	$15.94	1.2%
$140 to $160	$15.99	0.7%
Above $160	$25.01	0.7%

Day-Ahead Markup

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

Table 2-21 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March 2011 (See 2010 SOM, Table 2-22)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.77)	79.1%
Municipal waste	Steam	($0.00)	0.1%
Natural gas	CT	$0.01	(0.9%)
Natural gas	Diesel	$0.00	0.0%
Natural gas	Steam	($0.21)	21.1%
Oil	Steam	($0.01)	0.5%
Total		($0.98)	100.0%

Markup Component of Day-Ahead System Price

Table 2-22 Monthly markup components of day-ahead, load-weighted LMP: January through March 2011 (See 2010 SOM, Table 2-23)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.48)	$0.13	($1.04)
Feb	($1.36)	($1.14)	($1.59)
Mar	($1.18)	($0.44)	($2.04)
Annual	($0.98)	($0.46)	($1.51)

Markup Component of Day-Ahead Zonal Prices

Table 2-23 Day-ahead, average, zonal markup component: January through March 2011 (See 2010 SOM, Table 2-24)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.83)	($0.21)	($1.49)
AEP	($1.23)	($0.67)	($1.81)
AP	($1.15)	($0.47)	($1.87)
BGE	($1.04)	($0.40)	($1.69)
ComEd	($0.59)	($0.44)	($0.75)
DAY	($1.16)	($0.67)	($1.68)
DLCO	($1.23)	($0.79)	($1.70)
Dominion	($1.09)	($0.45)	($1.72)
DPL	($0.82)	($0.18)	($1.45)
JCPL	($0.98)	($0.47)	($1.55)
Met-Ed	($0.99)	($0.48)	($1.53)
PECO	($0.74)	($0.11)	($1.40)
PENELEC	($0.98)	($0.48)	($1.56)
Pepco	($1.04)	($0.43)	($1.70)
PPL	($0.94)	($0.52)	($1.39)
PSEG	($0.75)	($0.24)	($1.33)
RECO	($0.66)	($0.20)	($1.21)

Markup by Day-Ahead System Price Levels

Table 2-24 Average, day-ahead markup (By price category): January through March 2011 (See 2010 SOM, Table 2-25)

	Average Markup Component	Frequency
Below $20	$0.00	0%
$20 to $40	($2.25)	50%
$40 to $60	($0.47)	39%
$60 to $80	($0.82)	5%
$80 to $100	($0.01)	3%
$100 to $120	$2.62	1%
$120 to $140	($1.10)	0%
$140 to $160	($1.07)	0%
Above $160	($1.97)	0%

Frequently Mitigated Unit and Associated Unit Adders

Table 2-25 Frequently mitigated units and associated units (By month): January through March 2011 (See 2010 SOM, Table 2-26)

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
Jan	46	22	66	134
Feb	34	43	60	137
Mar	30	46	66	142

Table 2-26 Frequently mitigated units and associated units total months eligible: January through March 2011 (See 2010 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
Jan	4
Feb	14
Mar	127
Total	145

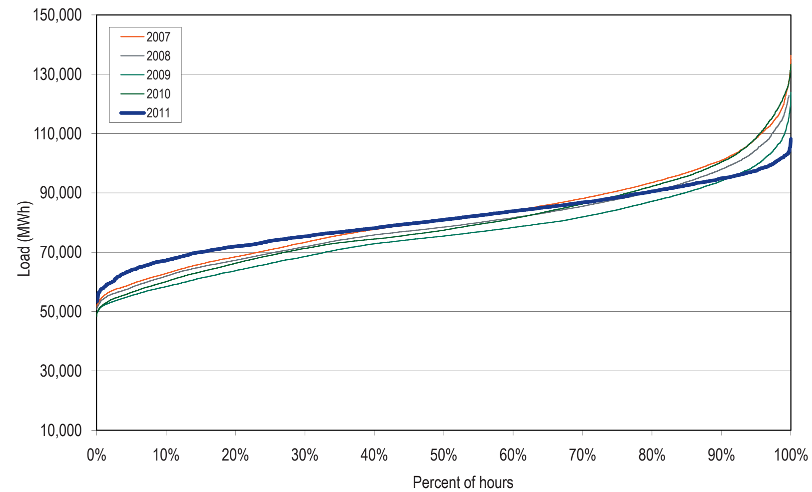
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-5 PJM real-time load duration curves: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-5)



PJM Real-Time, Annual Average Load

Table 2-27 PJM real-time average hourly load: Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-28)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	79,611	77,430	15,504	4.7%	2.6%	16.9%
2011	81,018	80,991	10,273	1.8%	4.6%	(33.7%)

PJM Real-Time, Monthly Average Load

Figure 2-6 PJM real-time average hourly load: Calendar years 2010 through March 2011 (See 2010 SOM, Figure 2-6)

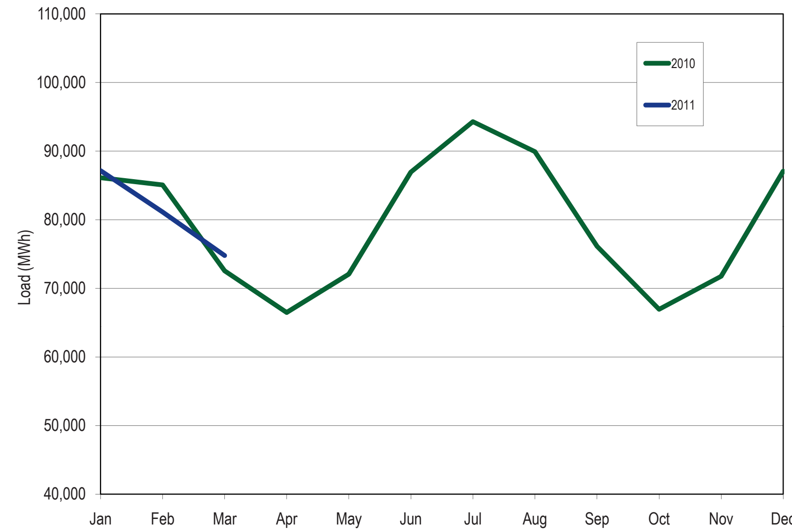


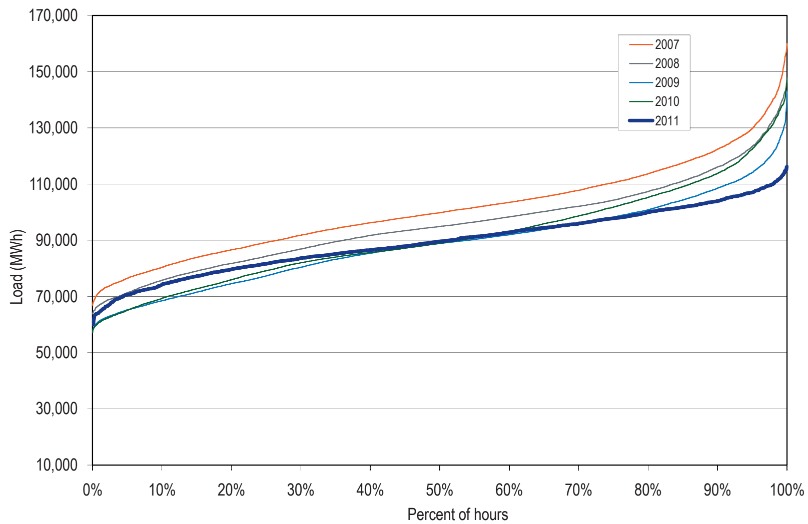
Table 2-28 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through March 2011 (See 2010 SOM, Table 2-30)

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.28	57.22
2011	NA	25.20	42.26

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-7)



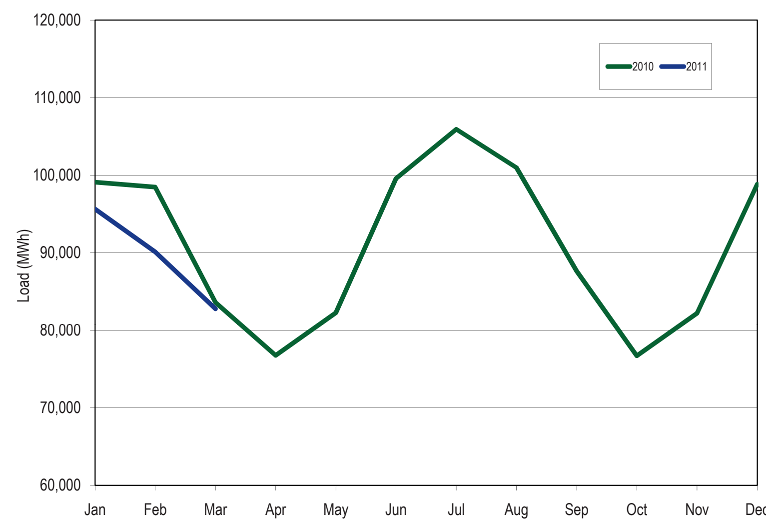
PJM Day-Ahead, Annual Average Load

Table 2-29 PJM day-ahead average load: Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	90,985	88,925	17,014	2.6%	0.1%	14.2%
2011	89,478	89,561	11,157	(1.7%)	0.7%	(34.4%)

PJM Day-Ahead, Monthly Average Load

Figure 2-8 PJM day-ahead average load: Calendar years 2010 through March 2011 (See 2010 SOM, Figure 2-8)



Real-Time and Day-Ahead Load

Table 2-30 Cleared day-ahead and real-time load (MWh): January through March 2011 (See 2010 SOM, Table 2-32)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	77,744	859	10,875	89,478	81,018	8,460	(2,415)
Median	77,437	852	10,734	89,561	80,991	8,570	(2,164)
Standard deviation	9,641	189	1,894	11,157	10,273	884	(1,011)
Peak average	83,588	950	11,877	96,416	87,187	9,229	(2,648)
Peak median	83,266	951	11,792	96,314	86,883	9,431	(2,362)
Peak standard deviation	7,314	176	1,603	8,069	7,700	369	(1,234)
Off peak average	72,472	777	9,970	83,219	75,453	7,766	(2,204)
Off peak median	72,228	772	9,769	82,878	74,949	7,929	(1,840)
Off peak standard deviation	8,365	161	1,668	9,770	9,055	716	(953)

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through March 2011 (See 2010 SOM, Figure 2-9)

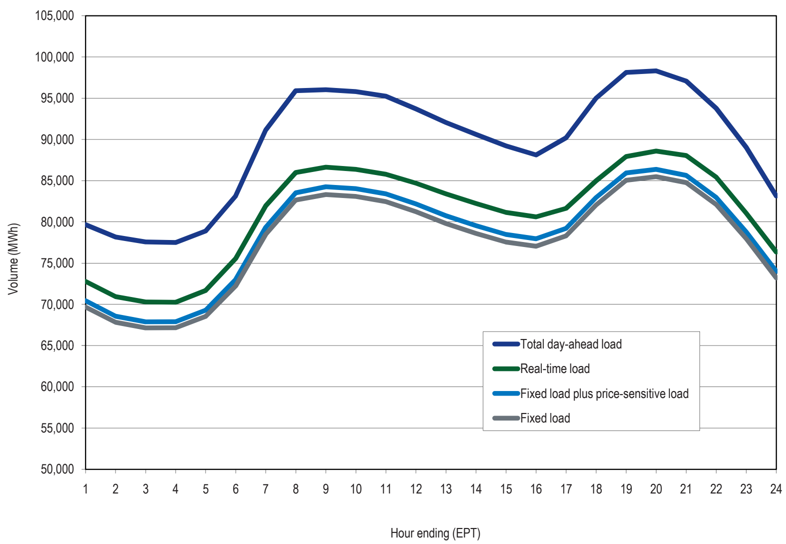
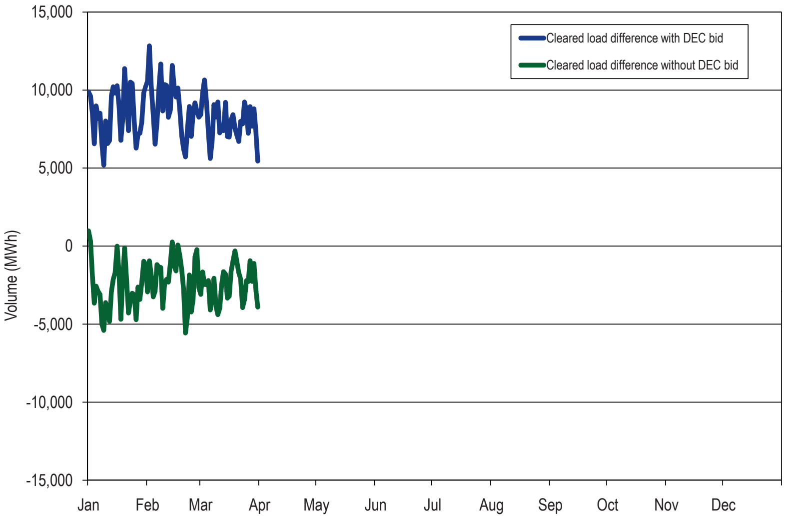


Figure 2-10 Difference between day-ahead and real-time loads (Average daily volumes): January through March 2011 (See 2010 SOM, Figure 2-10)



Real-Time and Day-Ahead Generation

Table 2-31 Day-ahead and real-time generation (MWh): January through March 2011 (See 2010 SOM, Table 2-33)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,725	7,947	92,672	83,505	1,220	9,168
Median	85,010	7,844	92,948	83,643	1,367	9,305
Standard deviation	10,911	1,134	11,463	10,116	795	1,347
Peak average	91,389	8,554	99,943	89,689	1,700	10,254
Peak median	91,319	8,412	99,787	89,381	1,938	10,406
Peak standard deviation	7,869	1,037	8,193	7,530	339	663
Off peak average	78,713	7,400	86,113	77,925	788	8,188
Off peak median	78,214	7,398	85,782	77,614	600	8,168
Off peak standard deviation	9,717	920	9,934	8,825	892	1,110

Figure 2-11 Day-ahead and real-time generation (Average hourly volumes): January through March 2011 (See 2010 SOM, Figure 2-11)

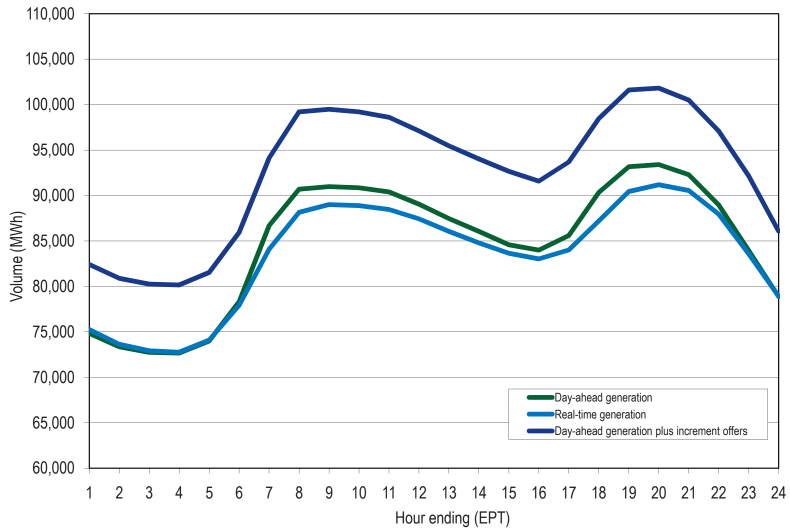
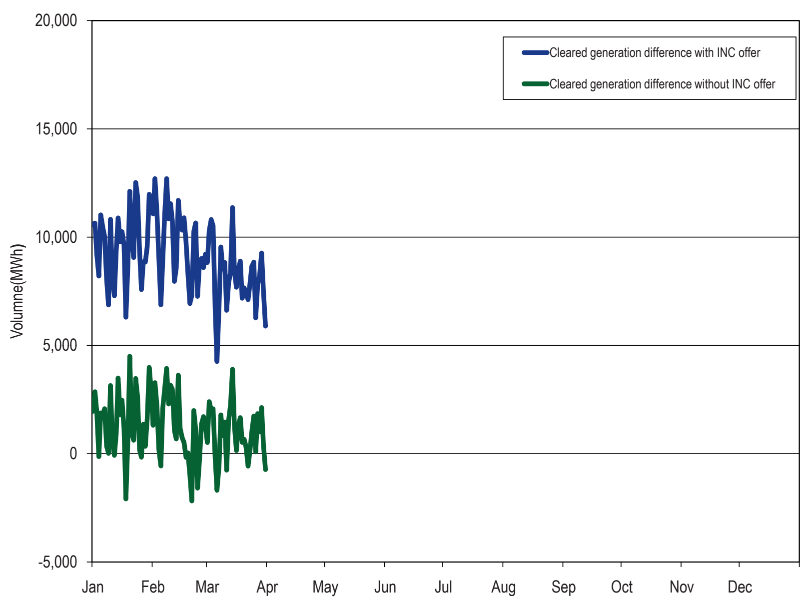


Figure 2-12 Difference between day-ahead and real-time generation (Average daily volumes): January through March 2011 (See 2010 SOM, Figure 2-12)



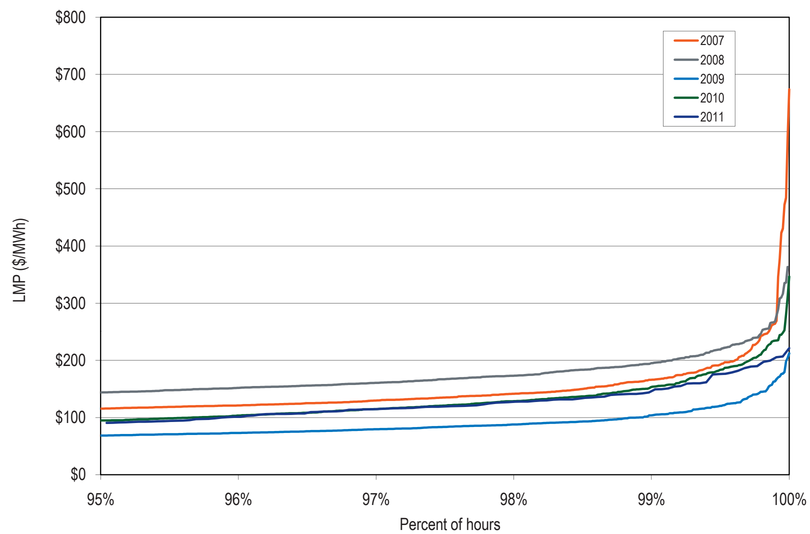
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-32 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-34)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$44.76	$38.14	$23.10	(0.2%)	3.4%	(11.9%)

Table 2-33 PJM real-time, simple average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-34)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$55.34	$47.15	$33.29	NA	NA	NA
2008 (Jan - Mar)	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009 (Jan - Mar)	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010 (Jan - Mar)	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011 (Jan - Mar)	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%

Zonal Real-Time, Annual Average LMP

Table 2-34 Zonal real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-35)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$48.31	$51.89	$3.59	7.4%
AEP	$39.41	$38.55	($0.86)	(2.2%)
AP	$43.67	$44.46	$0.78	1.8%
BGE	$50.44	$51.01	$0.57	1.1%
ComEd	$34.64	$34.40	($0.24)	(0.7%)
DAY	$38.69	$38.36	($0.33)	(0.9%)
DLCO	$39.65	$36.65	($3.01)	(7.6%)
Dominion	$49.43	$48.76	($0.67)	(1.4%)
DPL	$49.01	$51.24	$2.23	4.5%
JCPL	$47.96	$51.84	$3.88	8.1%
Met-Ed	$47.27	$49.36	$2.09	4.4%
PECO	$47.54	$50.57	$3.03	6.4%
PENELEC	$41.83	$44.44	$2.61	6.2%
Pepco	$50.44	$50.63	$0.20	0.4%
PPL	$46.66	$50.54	$3.89	8.3%
PSEG	$49.91	$52.64	$2.72	5.5%
RECO	$46.66	$46.94	$0.27	0.6%
PJM	$44.13	$44.76	$0.63	1.4%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-35 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-36)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$48.30	$50.51	$2.20	4.6%
Illinois	$34.64	$34.40	($0.24)	(0.7%)
Indiana	$37.85	$37.37	($0.48)	(1.3%)
Kentucky	$40.21	$38.60	($1.61)	(4.0%)
Maryland	$50.18	$50.68	$0.50	1.0%
Michigan	$38.54	$37.50	($1.04)	(2.7%)
New Jersey	$49.08	$52.21	$3.13	6.4%
North Carolina	$48.01	$46.41	($1.60)	(3.3%)
Ohio	$38.06	$38.01	($0.06)	(0.2%)
Pennsylvania	$45.06	$47.33	$2.27	5.0%
Tennessee	$41.90	$38.90	($3.00)	(7.2%)
Virginia	$48.61	$47.66	($0.95)	(2.0%)
West Virginia	$39.81	$40.00	$0.19	0.5%
District of Columbia	$50.72	$50.84	$0.13	0.2%

Hub Real-Time, Annual Average LMP

Table 2-36 Hub real-time, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-37)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AEP Gen Hub	$36.33	$35.96	($0.37)	(1.0%)
AEP-DAY Hub	$38.26	$37.63	($0.63)	(1.6%)
Chicago Gen Hub	$33.98	$33.44	($0.55)	(1.6%)
Chicago Hub	$34.78	$34.50	($0.28)	(0.8%)
Dominion Hub	$48.75	$47.87	($0.89)	(1.8%)
Eastern Hub	$48.93	$51.59	$2.66	5.4%
N Illinois Hub	$34.47	$34.10	($0.36)	(1.1%)
New Jersey Hub	$48.90	$52.27	$3.37	6.9%
Ohio Hub	$38.22	$37.63	($0.58)	(1.5%)
West Interface Hub	$40.96	$40.60	($0.36)	(0.9%)
Western Hub	$44.54	$45.82	$1.28	2.9%

Real-Time, Load-Weighted, Average LMP

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

Table 2-37 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through March 2011 (See 2010 SOM, Table 2-38)

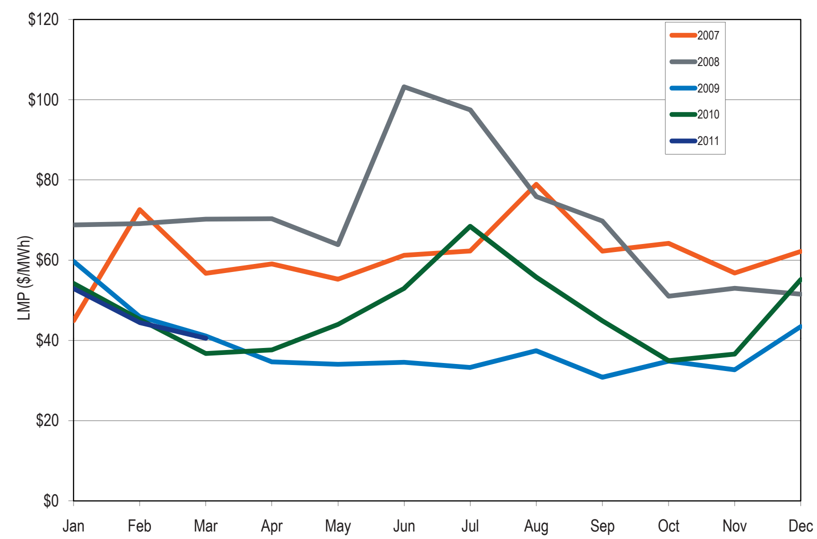
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$46.35	$39.11	$24.26	(4.1%)	(0.0%)	(16.1%)

Table 2-38 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-38)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$58.07	$50.60	$34.44	NA	NA	NA
2008 (Jan - Mar)	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009 (Jan - Mar)	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010 (Jan - Mar)	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011 (Jan - Mar)	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%

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

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-14)



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

Table 2-39 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-39)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$50.19	$54.19	$4.00	8.0%
AEP	$40.81	$39.41	($1.40)	(3.4%)
AP	$45.27	$45.91	$0.64	1.4%
BGE	$53.28	$53.86	$0.58	1.1%
ComEd	$35.85	$35.23	($0.62)	(1.7%)
DAY	$40.06	$39.33	($0.72)	(1.8%)
DLCO	$40.83	$37.14	($3.69)	(9.0%)
Dominion	$52.88	$51.82	($1.06)	(2.0%)
DPL	$51.74	$54.14	$2.40	4.6%
JCPL	$49.95	$54.19	$4.24	8.5%
Met-Ed	$49.14	$51.40	$2.26	4.6%
PECO	$49.39	$52.74	$3.35	6.8%
PENELEC	$42.93	$45.63	$2.70	6.3%
Pepco	$53.24	$53.35	$0.10	0.2%
PPL	$48.69	$52.84	$4.15	8.5%
PSEG	$51.60	$54.43	$2.83	5.5%
RECO	$48.33	$48.68	$0.35	0.7%
PJM	$45.92	$46.35	$0.43	0.9%

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-40 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-40)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$50.55	$53.00	$2.45	4.8%
Illinois	$35.85	$35.23	($0.62)	(1.7%)
Indiana	$38.66	$38.00	($0.66)	(1.7%)
Kentucky	$42.29	$39.97	($2.32)	(5.5%)
Maryland	$53.22	$53.64	$0.43	0.8%
Michigan	$39.63	$38.35	($1.28)	(3.2%)
New Jersey	$50.87	$54.22	$3.35	6.6%
North Carolina	$51.81	$49.24	($2.57)	(5.0%)
Ohio	$39.18	$38.72	($0.46)	(1.2%)
Pennsylvania	$46.66	$49.01	$2.35	5.0%
Tennessee	$45.24	$40.74	($4.50)	(9.9%)
Virginia	$51.97	$50.53	($1.44)	(2.8%)
West Virginia	$41.36	$41.05	($0.31)	(0.8%)
District of Columbia	$52.70	$52.71	$0.01	0.0%

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

Fuel Cost

Figure 2-15 Spot average fuel price comparison: Calendar years 2010 through March 2011 (See 2010 SOM, Table 2-15)

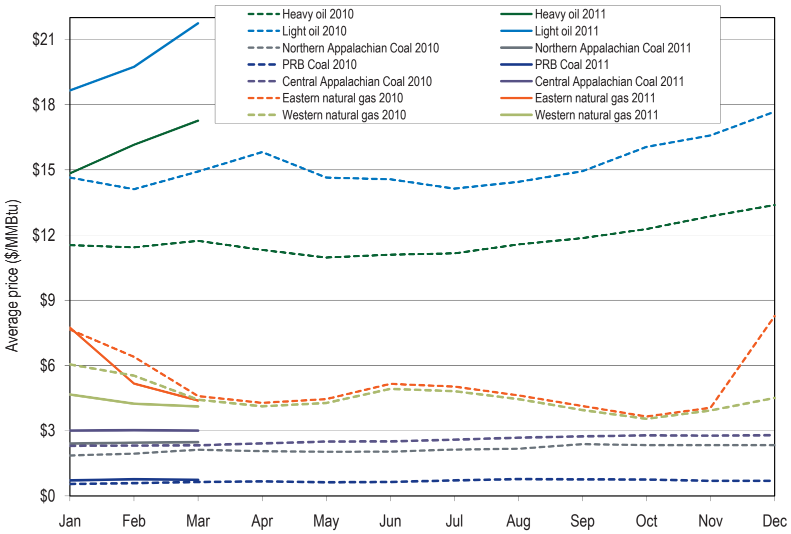


Table 2-41 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-41)

	2011 Load-Weighted LMP	2011 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$46.35	$42.73	(7.8%)
	2010 Load-Weighted LMP	**2011 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$45.92	$42.73	(7.0%)
	2010 Load-Weighted LMP	**2011 Load-Weighted LMP**	**Change**
Average	$45.92	$46.35	0.9%

Components of Real-Time, Load-Weighted LMP

Table 2-42 Components of PJM real-time, load-weighted, average LMP: January through March 2011 (See 2010 SOM, Table 2-42)

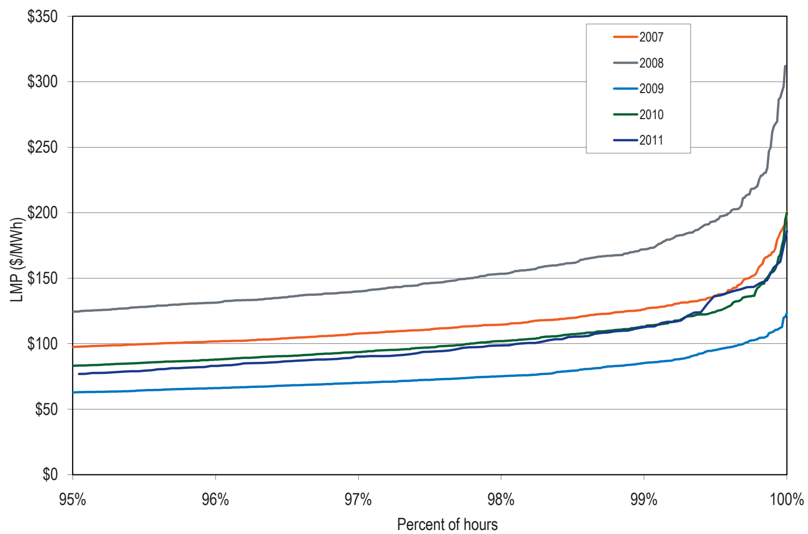
Element	Contribution to LMP	Percent
Coal	$21.54	46.5%
Gas	$14.32	30.9%
10% Cost Adder	$3.93	8.5%
VOM	$2.34	5.0%
NA	$2.29	4.9%
NO_x	$0.59	1.3%
Markup	$0.48	1.0%
Oil	$0.36	0.8%
CO_2	$0.36	0.8%
SO_2	$0.06	0.1%
FMU Adder	$0.04	0.1%
Dispatch Differential	$0.03	0.1%
Unit LMP Differential	$0.02	0.0%
M2M Adder	$0.01	0.0%
Municipal Waste	$0.00	0.0%
Shadow Price Limit Adder	($0.00)	(0.0%)
Wind	($0.01)	(0.0%)
Total	$46.35	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-16 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2007 through March 2011 (See 2010 SOM, Figure 2-16)



PJM Day-Ahead, Annual Average LMP

Table 2-43 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$45.60	$41.10	$16.82	2.3%	2.8%	(10.6%)

Table 2-44 PJM day-ahead, simple average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-43)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$52.76	$49.43	$22.59	NA	NA	NA
2008 (Jan - Mar)	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009 (Jan - Mar)	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010 (Jan - Mar)	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011 (Jan - Mar)	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%

Zonal Day-Ahead, Annual Average LMP

Table 2-45 Zonal day-ahead, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-44)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$50.98	$53.79	$2.80	5.5%
AEP	$40.38	$38.88	($1.50)	(3.7%)
AP	$45.11	$45.20	$0.09	0.2%
BGE	$53.96	$52.74	($1.22)	(2.3%)
ComEd	$35.75	$34.32	($1.43)	(4.0%)
DAY	$39.22	$38.53	($0.69)	(1.8%)
DLCO	$39.71	$36.62	($3.09)	(7.8%)
Dominion	$53.30	$50.66	($2.64)	(5.0%)
DPL	$51.32	$54.16	$2.84	5.5%
JCPL	$51.09	$54.22	$3.14	6.1%
Met-Ed	$50.23	$51.43	$1.20	2.4%
PECO	$50.53	$53.42	$2.89	5.7%
PENELEC	$44.51	$45.12	$0.61	1.4%
Pepco	$54.23	$52.35	($1.88)	(3.5%)
PPL	$49.71	$52.46	$2.75	5.5%
PSEG	$52.23	$55.55	$3.33	6.4%
RECO	$50.69	$51.83	$1.14	2.3%
PJM	$46.13	$45.60	($0.54)	(1.2%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-46 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-45)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$50.73	$53.27	$2.53	5.0%
Illinois	$35.75	$34.32	($1.43)	(4.0%)
Indiana	$38.60	$37.72	($0.88)	(2.3%)
Kentucky	$40.81	$38.95	($1.85)	(4.5%)
Maryland	$53.50	$52.49	($1.02)	(1.9%)
Michigan	$39.18	$37.97	($1.21)	(3.1%)
New Jersey	$51.73	$54.89	$3.16	6.1%
North Carolina	$51.71	$48.94	($2.76)	(5.3%)
Ohio	$38.60	$38.00	($0.61)	(1.6%)
Pennsylvania	$47.48	$48.98	$1.50	3.2%
Tennessee	$43.18	$39.25	($3.93)	(9.1%)
Virginia	$52.25	$49.46	($2.79)	(5.3%)
West Virginia	$40.63	$40.59	($0.03)	(0.1%)
District of Columbia	$54.58	$52.47	($2.12)	(3.9%)

Day-Ahead, Load-Weighted, Average LMP

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

Table 2-47 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-46)

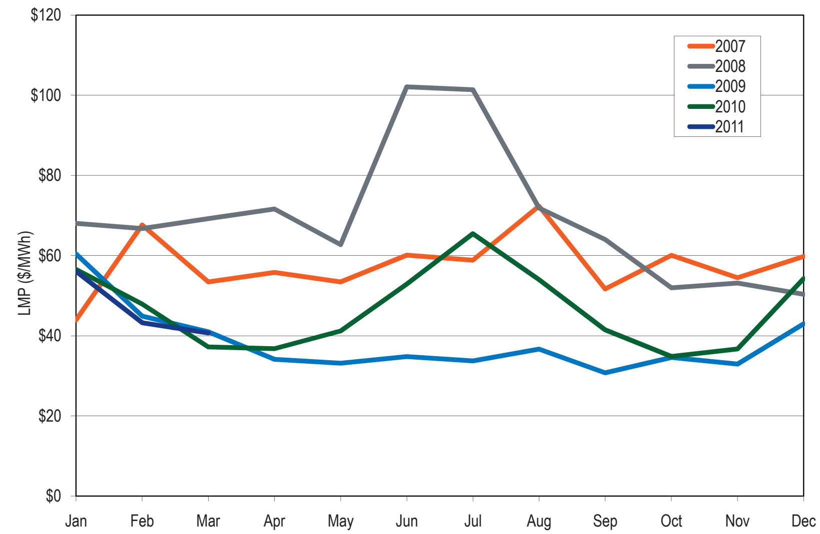
	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$47.14	$42.49	$17.73	(1.1%)	1.0%	(13.9%)

Table 2-48 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2007 through 2011 (See 2010 SOM, Table 2-46)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2007 (Jan - Mar)	$54.87	$51.89	$23.16	NA	NA	NA
2008 (Jan - Mar)	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009 (Jan - Mar)	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010 (Jan - Mar)	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011 (Jan - Mar)	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%

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

Figure 2-17 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2007 through March 2011 (See 2010 SOM, Table 2-17)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-49 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-47)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
AECO	$53.66	$56.13	$2.48	4.6%
AEP	$41.63	$39.70	($1.93)	(4.6%)
AP	$46.61	$46.59	($0.02)	(0.0%)
BGE	$56.54	$55.47	($1.07)	(1.9%)
ComEd	$36.57	$34.93	($1.64)	(4.5%)
DAY	$40.48	$39.41	($1.08)	(2.7%)
DLCO	$41.01	$37.25	($3.76)	(9.2%)
Dominion	$56.74	$53.76	($2.98)	(5.2%)
DPL	$53.72	$57.23	$3.51	6.5%
JCPL	$52.89	$56.60	$3.70	7.0%
Met-Ed	$52.07	$53.28	$1.21	2.3%
PECO	$52.47	$56.02	$3.54	6.8%
PENELEC	$45.47	$46.51	$1.05	2.3%
Pepco	$56.02	$54.87	($1.16)	(2.1%)
PPL	$51.86	$54.72	$2.86	5.5%
PSEG	$53.75	$57.49	$3.74	7.0%
RECO	$53.11	$53.93	$0.82	1.5%
PJM	$47.77	$47.14	($0.63)	(1.3%)

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-50 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-48)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Difference	Difference as Percent of 2010
Delaware	$53.05	$55.95	$2.90	5.5%
Illinois	$36.57	$34.93	($1.64)	(4.5%)
Indiana	$39.57	$38.35	($1.22)	(3.1%)
Kentucky	$42.19	$40.06	($2.13)	(5.1%)
Maryland	$55.89	$55.23	($0.66)	(1.2%)
Michigan	$39.96	$38.64	($1.32)	(3.3%)
New Jersey	$53.46	$56.98	$3.52	6.6%
North Carolina	$54.78	$52.45	($2.32)	(4.2%)
Ohio	$39.67	$38.69	($0.98)	(2.5%)
Pennsylvania	$49.00	$50.78	$1.79	3.6%
Tennessee	$45.10	$40.63	($4.47)	(9.9%)
Virginia	$55.39	$52.25	($3.14)	(5.7%)
West Virginia	$41.98	$41.51	($0.47)	(1.1%)
District of Columbia	$55.86	$54.61	($1.25)	(2.2%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-51 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-49)

Element	Contribution to LMP	Percent
Coal	$12.89	27.3%
DEC	$11.58	24.6%
INC	$7.99	17.0%
Natural gas	$6.81	14.4%
Transaction	$3.56	7.6%
10% Cost Adder	$2.16	4.6%
Price Sensitive Demand	$1.28	2.7%
VOM	$1.23	2.6%
NO_x	$0.32	0.7%
CO_2	$0.22	0.5%
Oil	$0.12	0.2%
SO_2	$0.03	0.1%
Constrained Off	($0.00)	(0.0%)
Markup	($0.98)	(2.1%)
NA	($0.08)	(0.2%)
Total	$47.14	100.0%

Marginal Losses

Table 2-52 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2011 (See 2010 SOM, Table 2-50)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011 (Jan - Mar)	$44.76	$44.70	$0.03	$0.02

Table 2-53 Zonal real-time, simple average LMP components (Dollars per MWh): January through March 2010 and 2011 (See 2010 SOM, Table 2-51)

	2010 (Jan - Mar)				2011 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.31	$44.02	$1.73	$2.55	$51.89	$44.70	$4.81	$2.38
AEP	$39.41	$44.02	($2.98)	($1.64)	$38.55	$44.70	($4.46)	($1.69)
AP	$43.67	$44.02	($0.33)	($0.02)	$44.46	$44.70	($0.31)	$0.06
BGE	$50.44	$44.02	$4.06	$2.36	$51.01	$44.70	$4.19	$2.12
ComEd	$34.64	$44.02	($6.15)	($3.23)	$34.40	$44.70	($7.15)	($3.15)
DAY	$38.69	$44.02	($4.15)	($1.18)	$38.36	$44.70	($5.16)	($1.18)
DLCO	$39.65	$44.02	($2.67)	($1.70)	$36.65	$44.70	($6.76)	($1.29)
Dominion	$49.43	$44.02	$4.52	$0.89	$48.76	$44.70	$3.36	$0.70
DPL	$49.01	$44.02	$2.18	$2.81	$51.24	$44.70	$3.53	$3.01
JCPL	$47.96	$44.02	$1.34	$2.59	$51.84	$44.70	$4.48	$2.67
Met-Ed	$47.27	$44.02	$1.71	$1.54	$49.36	$44.70	$3.46	$1.20
PECO	$47.54	$44.02	$1.72	$1.80	$50.57	$44.70	$3.95	$1.91
PENELEC	$41.83	$44.02	($1.93)	($0.26)	$44.44	$44.70	($0.72)	$0.46
Pepco	$50.44	$44.02	$4.86	$1.56	$50.63	$44.70	$4.64	$1.29
PPL	$46.66	$44.02	$1.47	$1.16	$50.54	$44.70	$4.68	$1.16
PSEG	$49.91	$44.02	$3.31	$2.58	$52.64	$44.70	$5.33	$2.61
RECO	$46.66	$44.02	$0.44	$2.20	$46.94	$44.70	($0.16)	$2.39

Table 2-54 Hub real-time, simple average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-52)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$35.96	$44.70	($5.63)	($3.12)
AEP-DAY Hub	$37.63	$44.70	($5.15)	($1.92)
Chicago Gen Hub	$33.44	$44.70	($7.53)	($3.73)
Chicago Hub	$34.50	$44.70	($7.07)	($3.12)
Dominion Hub	$47.87	$44.70	$2.91	$0.25
Eastern Hub	$51.59	$44.70	$3.74	$3.15
N Illinois Hub	$34.10	$44.70	($7.22)	($3.37)
New Jersey Hub	$52.27	$44.70	$4.99	$2.57
Ohio Hub	$37.63	$44.70	($5.16)	($1.90)
West Interface Hub	$40.60	$44.70	($2.80)	($1.30)
Western Hub	$45.82	$44.70	$1.05	$0.06

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-55 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-53)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.19	$46.25	$5.42	$2.52
AEP	$39.41	$46.16	($4.99)	($1.76)
AP	$45.91	$46.34	($0.48)	$0.05
BGE	$53.86	$46.70	$4.94	$2.23
ComEd	$35.23	$45.79	($7.33)	($3.23)
DAY	$39.33	$46.25	($5.71)	($1.21)
DLCO	$37.14	$45.88	($7.38)	($1.36)
Dominion	$51.82	$46.85	$4.23	$0.74
DPL	$54.14	$46.75	$4.14	$3.25
JCPL	$54.19	$46.35	$5.02	$2.82
Met-Ed	$51.40	$46.26	$3.87	$1.28
PECO	$52.74	$46.31	$4.41	$2.02
PENELEC	$45.63	$46.01	($0.84)	$0.46
Pepco	$53.35	$46.61	$5.39	$1.35
PPL	$52.84	$46.42	$5.18	$1.24
PSEG	$54.43	$45.99	$5.71	$2.73
RECO	$48.68	$46.12	$0.05	$2.51
PJM	$46.35	$46.30	$0.03	$0.03

Table 2-56 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2011 (See 2010 SOM, Table 2-54)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$44.57	$44.61	$0.03	($0.06)
2011 (Jan - Mar)	$45.60	$45.81	($0.11)	($0.11)

Table 2-57 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through March 2010 to 2011 (See 2010 SOM, Table 2-55)

	2010 (Jan - Mar)				2011 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.98	$46.10	$2.11	$2.77	$53.79	$45.81	$5.01	$2.97
AEP	$40.38	$46.10	($3.49)	($2.23)	$38.88	$45.81	($4.66)	($2.27)
AP	$45.11	$46.10	($1.04)	$0.05	$45.20	$45.81	($0.52)	($0.09)
BGE	$53.96	$46.10	$4.64	$3.22	$52.74	$45.81	$4.57	$2.36
ComEd	$35.75	$46.10	($6.12)	($4.23)	$34.32	$45.81	($7.78)	($3.70)
DAY	$39.22	$46.10	($4.79)	($2.09)	$38.53	$45.81	($5.42)	($1.85)
DLCO	$39.71	$46.10	($4.39)	($2.00)	$36.62	$45.81	($7.42)	($1.76)
Dominion	$53.30	$46.10	$5.61	$1.58	$50.66	$45.81	$3.73	$1.12
DPL	$51.32	$46.10	$2.36	$2.85	$54.16	$45.81	$4.69	$3.67
JCPL	$51.09	$46.10	$1.77	$3.21	$54.22	$45.81	$5.01	$3.41
Met-Ed	$50.23	$46.10	$2.32	$1.81	$51.43	$45.81	$4.29	$1.33
PECO	$50.53	$46.10	$2.14	$2.28	$53.42	$45.81	$5.05	$2.56
PENELEC	$44.51	$46.10	($1.97)	$0.37	$45.12	$45.81	($0.91)	$0.22
Pepco	$54.23	$46.10	$5.69	$2.44	$52.35	$45.81	$4.85	$1.69
PPL	$49.71	$46.10	$2.23	$1.38	$52.46	$45.81	$5.42	$1.23
PSEG	$52.23	$46.10	$2.76	$3.37	$55.55	$45.81	$6.16	$3.58
RECO	$50.69	$46.10	$1.69	$2.90	$51.83	$45.81	$2.92	$3.10

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-58 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-56)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$56.13	$47.42	$5.58	$3.13
AEP	$39.70	$47.24	($5.17)	($2.37)
AP	$46.59	$47.42	($0.72)	($0.11)
BGE	$55.47	$47.74	$5.23	$2.50
ComEd	$34.93	$46.71	($8.01)	($3.77)
DAY	$39.41	$47.25	($5.91)	($1.93)
DLCO	$37.25	$46.94	($7.85)	($1.84)
Dominion	$53.76	$48.01	$4.52	$1.23
DPL	$57.23	$47.90	$5.41	$3.92
JCPL	$56.60	$47.47	$5.54	$3.59
Met-Ed	$53.28	$47.21	$4.66	$1.41
PECO	$56.02	$47.54	$5.76	$2.72
PENELEC	$46.51	$47.39	($1.10)	$0.23
Pepco	$54.87	$47.59	$5.48	$1.79
PPL	$54.72	$47.54	$5.88	$1.30
PSEG	$57.49	$47.21	$6.55	$3.73
RECO	$53.93	$47.42	$3.27	$3.25
PJM	$47.14	$47.36	($0.11)	($0.11)

Marginal Loss Costs and Loss Credits

Table 2-59 Marginal loss costs and loss credits: Calendar years 2007 through March 2011[10] (See 2010 SOM, Table 2-57)

	Total Marginal Loss Costs	Loss Credits	Percent
2007	$1,246,944,931	$630,277,662	50.5%
2008	$2,493,333,212	$1,309,286,301	52.5%
2009	$1,268,085,226	$639,684,849	50.4%
2010	$1,634,719,184	$836,683,849	51.2%
2011 (Jan - Mar)	$409,597,112	$200,148,617	48.9%

10 2007 only includes data from June 1, 2007 through December 31, 2007. PJM began including marginal losses in economic dispatch and LMP models on June 1, 2007.

Monthly Marginal Loss Costs

Table 2-60 Marginal loss costs by type (Dollars (Millions)): January through March 2011 (See 2010 SOM, Table 2-58)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$41.8	($134.4)	$12.3	$188.5	$4.4	$1.9	($5.4)	($2.9)	$185.7
Feb	$26.8	($88.2)	$6.8	$121.8	$2.4	$2.3	($1.9)	($1.8)	$119.9
Mar	$22.9	($79.1)	$6.8	$108.8	$1.1	$2.2	($3.8)	($4.8)	$104.0
Total	$91.4	($301.7)	$26.0	$419.1	$7.9	$6.3	($11.1)	($9.5)	$409.6

Zonal Marginal Loss Costs

Table 2-61 Marginal loss costs by control zone and type (Dollars (Millions)): January through March 2011 (See 2010 SOM, Table 2-59)

	Marginal Loss Costs by Control Zone (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$7.9	$1.6	$0.2	$6.4	$0.2	($0.3)	($0.1)	$0.3	$6.7
AEP	($21.7)	($109.0)	$8.8	$96.0	$0.4	$2.9	($2.3)	($4.8)	$91.3
AP	($1.2)	($30.8)	$2.5	$32.2	$0.8	$1.4	($1.2)	($1.8)	$30.4
BGE	$18.5	$4.7	$1.3	$15.1	$0.8	($0.5)	($1.0)	$0.3	$15.4
ComEd	($63.0)	($130.8)	$4.1	$72.0	$6.4	$1.7	$0.7	$5.4	$77.3
DAY	($1.5)	($16.8)	$1.2	$16.5	($0.1)	$1.2	($0.5)	($1.7)	$14.7
DLCO	($5.6)	($10.6)	$0.2	$5.2	($0.6)	$0.0	($0.1)	($0.7)	$4.4
Dominion	$26.0	($13.1)	$2.2	$41.4	$0.7	($0.3)	($1.3)	($0.3)	$41.1
DPL	$19.8	$2.5	$0.4	$17.7	($1.0)	($0.3)	($0.3)	($1.1)	$16.6
JCPL	$21.0	$7.5	$0.1	$13.5	($0.1)	($0.1)	($0.1)	($0.1)	$13.5
Met-Ed	$5.5	$0.9	$0.0	$4.6	$0.1	($0.2)	($0.0)	$0.2	$4.8
PECO	$25.2	$11.5	$0.4	$14.1	($0.3)	($0.0)	($0.3)	($0.6)	$13.6
PENELEC	($3.1)	($20.8)	($0.1)	$17.6	$0.5	$0.3	($0.0)	$0.2	$17.8
Pepco	$17.8	$4.6	$1.6	$14.8	($0.6)	($0.6)	($1.3)	($1.3)	$13.5
PJM	($2.2)	($12.6)	($1.5)	$8.9	($0.0)	($3.0)	($0.5)	$2.5	$11.4
PPL	$13.7	($1.1)	$0.8	$15.6	$1.2	$0.4	($0.2)	$0.6	$16.2
PSEG	$33.2	$10.5	$3.8	$26.5	($0.4)	$3.9	($2.5)	($6.8)	$19.7
RECO	$1.2	$0.2	$0.1	$1.0	($0.0)	($0.2)	($0.0)	$0.1	$1.1
Total	$91.4	($301.7)	$26.0	$419.1	$7.9	$6.3	($11.1)	($9.5)	$409.6

Table 2-62 Monthly marginal loss costs by control zone (Dollars (Millions)): January through March 2011 (See 2010 SOM, Table 2-60)

	Marginal Loss Costs by Control Zone (Millions)			
	Jan	Feb	Mar	Grand Total
AECO	$2.9	$2.0	$1.8	$6.7
AEP	$41.9	$25.6	$23.8	$91.3
AP	$14.3	$8.4	$7.7	$30.4
BGE	$6.5	$5.0	$3.9	$15.4
ComEd	$32.3	$21.9	$23.1	$77.3
DAY	$5.2	$5.0	$4.5	$14.7
DLCO	$2.2	$1.6	$0.7	$4.4
Dominion	$19.8	$11.6	$9.7	$41.1
DPL	$7.7	$5.3	$3.6	$16.6
JCPL	$6.2	$4.1	$3.1	$13.5
Met-Ed	$2.1	$1.4	$1.4	$4.8
PECO	$6.6	$3.5	$3.5	$13.6
PENELEC	$8.9	$5.3	$3.6	$17.8
Pepco	$5.9	$3.7	$3.9	$13.5
PJM	$6.9	$4.3	$0.2	$11.4
PPL	$8.6	$4.7	$3.0	$16.2
PSEG	$7.3	$6.1	$6.3	$19.7
RECO	$0.5	$0.3	$0.3	$1.1
Total	$185.7	$119.9	$104.0	$409.6

Virtual Offers and Bids

Table 2-63 Monthly volume of cleared and submitted INCs, DECs: January through March 2011 (See 2010 SOM, Table 2-61)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	8,137	14,299	218	1,077	11,135	17,917	224	963
Feb	8,532	16,263	215	1,672	11,076	17,355	230	1,034
Mar	7,230	13,164	201	1,059	10,435	16,343	219	982
Annual	7,948	14,520	211	1,256	10,876	17,201	224	991

Table 2-64 Type of day-ahead marginal units: January through March 2011 (See 2010 SOM, Table 2-62)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	11.2%	64.7%	13.5%	10.2%	0.3%
Feb	10.1%	68.1%	12.7%	8.8%	0.3%
Mar	9.5%	67.2%	15.3%	7.6%	0.3%
Annual	10.3%	66.6%	13.9%	8.9%	0.3%

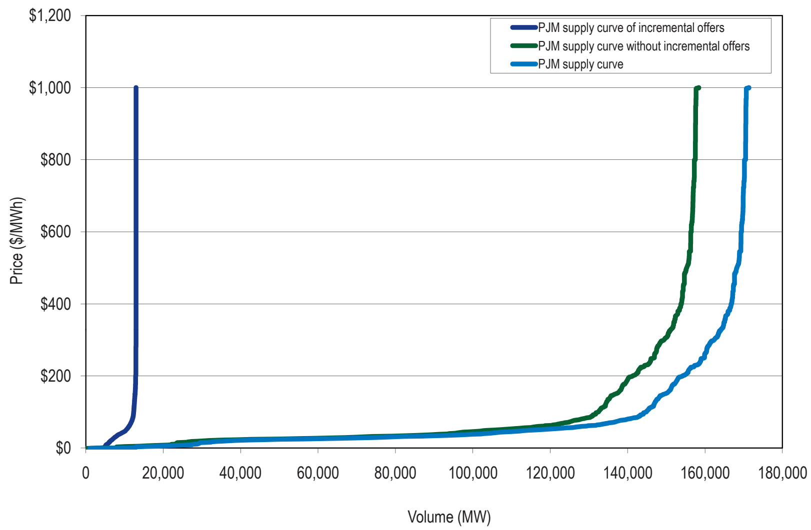
Table 2-65 PJM virtual bids by type of bid parent organization (MW): January through March 2011 (See 2010 SOM, Table 2-63)

	Category	Total Virtual Bids MW	Percentage
2011	Financial	35,014,214	51.1%
2011	Physical	33,469,428	48.9%
2011	Total	68,483,641	100.0%

Table 2-66 PJM virtual offers and bids by top ten aggregates (MW): January through March 2011 (See 2010 SOM, Table 2-64)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,426,945	6,902,555	13,329,499
N ILLINOIS HUB	HUB	2,625,577	4,527,187	7,152,764
AEP-DAYTON HUB	HUB	1,480,676	1,641,866	3,122,541
SOUTHIMP	INTERFACE	1,731,983	0	1,731,983
MISO	INTERFACE	68,374	1,244,714	1,313,088
PECO	ZONE	296,203	999,453	1,295,656
PPL	ZONE	104,239	993,763	1,098,001
IMO	INTERFACE	808,906	85,891	894,798
ComEd	ZONE	680,972	165,165	846,137
BGE	ZONE	48,094	762,176	810,270
Top ten total		14,271,967	17,322,770	31,594,736
PJM total		31,347,701	37,135,940	68,483,641
Top ten total as percent of PJM total		46.0%	47.0%	46.0%

Figure 2-18 PJM day-ahead aggregate supply curves: 2011 example day (See 2010 SOM, Figure 2-18)



Price Convergence

Table 2-67 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-65)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.60	$44.76	($0.84)	(1.9%)
Median	$41.10	$38.14	($2.96)	(7.8%)
Standard deviation	$16.82	$23.10	$6.27	27.2%
Peak average	$50.24	$49.26	($0.98)	(2.0%)
Peak median	$45.77	$42.16	($3.61)	(8.6%)
Peak standard deviation	$16.21	$23.06	$6.86	29.7%
Peak average	$41.41	$40.70	($0.71)	(1.7%)
Peak median	$36.85	$34.85	($2.00)	(5.7%)
Peak standard deviation	$16.27	$22.37	$6.10	27.3%

Table 2-68 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through March 2011 (See 2010 SOM, Table 2-66)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.0%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$45.60	$44.76	($0.84)	(1.8%)

Table 2-69 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2007 through March 2011 (See 2010 SOM, Table 2-67)

	2007		2008		2009		2010		2011	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	1	0.05%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	17	0.83%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	1,464	68.64%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	619	97.31%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	51	99.68%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	6	99.95%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	1	100.00%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	0	100.00%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-19 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March 2011 (See 2010 SOM, Figure 2-19)

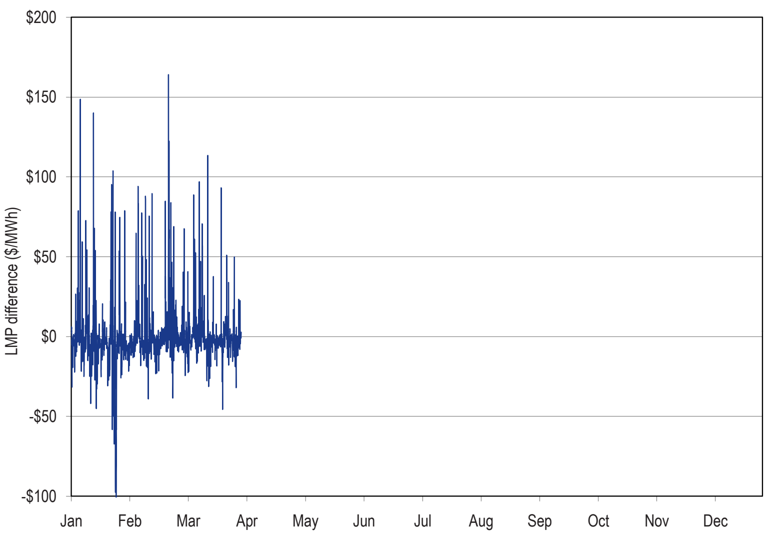


Figure 2-20 Monthly simple average of real-time minus day-ahead LMP: January through March 2011 (See 2010 SOM, Figure 2-20)

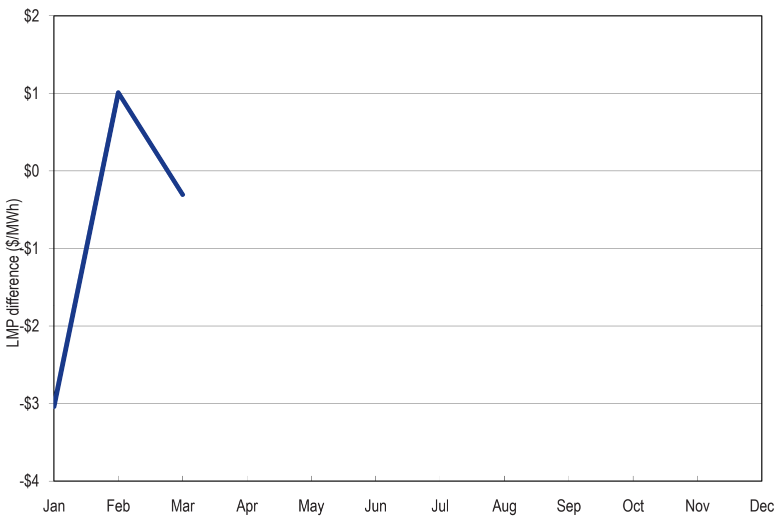
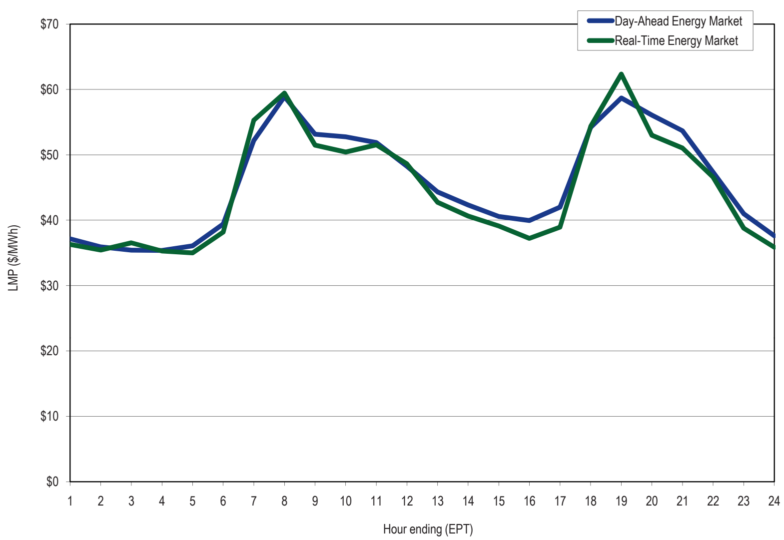


Figure 2-21 PJM system simple hourly average LMP: January through March 2011 (See 2010 SOM, Figure 2-21)



Zonal Price Convergence

Table 2-70 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-68)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$53.79	$51.89	($1.89)	(3.5%)
AEP	$38.88	$38.55	($0.33)	(0.9%)
AP	$45.20	$44.46	($0.74)	(1.6%)
BGE	$52.74	$51.01	($1.73)	(3.3%)
ComEd	$34.32	$34.40	$0.08	0.2%
DAY	$38.53	$38.36	($0.17)	(0.4%)
DLCO	$36.62	$36.65	$0.02	0.1%
Dominion	$50.66	$48.76	($1.90)	(3.7%)
DPL	$54.16	$51.24	($2.92)	(5.4%)
JCPL	$54.22	$51.84	($2.38)	(4.4%)
Met-Ed	$51.43	$49.36	($2.07)	(4.0%)
PECO	$53.42	$50.57	($2.85)	(5.3%)
PENELEC	$45.12	$44.44	($0.68)	(1.5%)
Pepco	$52.35	$50.63	($1.71)	(3.3%)
PPL	$52.46	$50.54	($1.92)	(3.7%)
PSEG	$55.55	$52.64	($2.91)	(5.2%)
RECO	$51.83	$46.94	($4.89)	(9.4%)

Price Convergence by Jurisdiction

Table 2-71 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 2-69)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$53.27	$50.51	($2.76)	(5.2%)
Illinois	$34.32	$34.40	$0.08	0.2%
Indiana	$37.72	$37.37	($0.35)	(0.9%)
Kentucky	$38.95	$38.60	($0.36)	(0.9%)
Maryland	$52.49	$50.68	($1.81)	(3.5%)
Michigan	$37.97	$37.50	($0.47)	(1.2%)
New Jersey	$54.89	$52.21	($2.67)	(4.9%)
North Carolina	$48.94	$46.41	($2.54)	(5.2%)
Ohio	$38.00	$38.01	$0.01	0.0%
Pennsylvania	$48.98	$47.33	($1.65)	(3.4%)
Tennessee	$39.25	$38.90	($0.35)	(0.9%)
Virginia	$49.46	$47.66	($1.80)	(3.6%)
West Virginia	$40.59	$40.00	($0.59)	(1.5%)
District of Columbia	$52.47	$50.84	($1.62)	(3.1%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-72 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2010 to March 2011 (See 2010 SOM, Table 2-70)

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.0%	17.4%	70.5%	9.3%	28.8%	61.9%	(2.7%)	11.4%	(8.6%)
Feb	13.5%	18.1%	68.4%	10.9%	27.9%	61.2%	(2.6%)	9.8%	(7.2%)
Mar	12.8%	18.2%	68.9%	10.4%	29.3%	60.3%	(2.5%)	11.1%	(8.6%)
Apr	12.6%	19.3%	68.1%						
May	11.6%	19.9%	68.5%						
Jun	10.4%	19.0%	70.5%						
Jul	9.8%	19.5%	70.7%						
Aug	10.6%	20.5%	68.9%						
Sep	12.0%	22.3%	65.7%						
Oct	13.0%	25.1%	61.9%						
Nov	12.8%	22.7%	64.5%						
Dec	11.5%	21.8%	66.7%						
Annual	11.8%	20.2%	68.0%	10.1%	28.7%	61.2%	(1.7%)	8.4%	(6.8%)

Day-Ahead Load and Spot Market

Table 2-73 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2010 to March 2011 (See 2010 SOM, Table 2-71)

	2010			2011			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.6%	17.8%	77.6%	5.1%	27.0%	67.9%	0.5%	9.2%	(9.7%)
Feb	4.6%	18.4%	77.0%	5.9%	26.5%	67.6%	1.3%	8.1%	(9.4%)
Mar	4.8%	18.4%	76.8%	6.2%	27.6%	66.2%	1.4%	9.1%	(10.6%)
Apr	4.9%	19.1%	76.0%						
May	6.6%	19.0%	74.4%						
Jun	4.6%	18.6%	76.7%						
Jul	4.7%	18.6%	76.6%						
Aug	4.8%	19.3%	75.9%						
Sep	4.6%	20.7%	74.8%						
Oct	4.9%	22.7%	72.4%						
Nov	4.9%	20.7%	74.4%						
Dec	4.6%	19.2%	76.2%						
Annual	4.9%	19.3%	75.8%	5.7%	27.0%	67.3%	0.8%	7.7%	(8.6%)

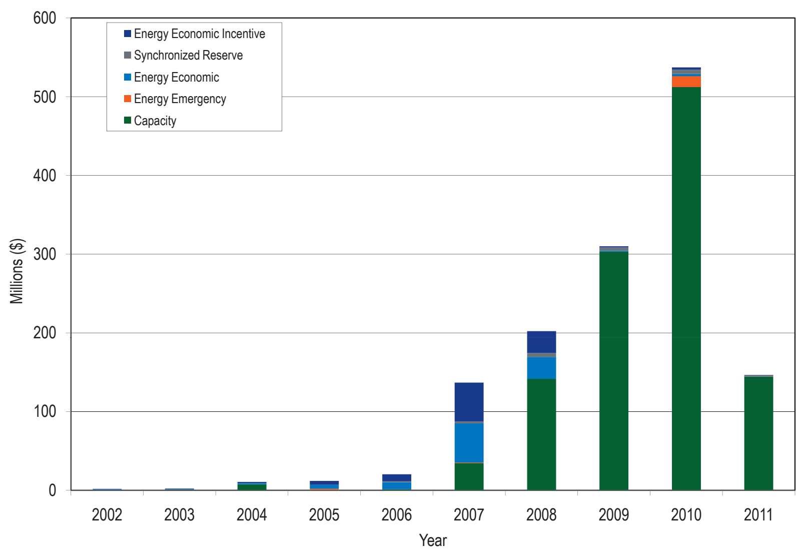
Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-74 Overview of Demand Side Programs (See 2010 SOM, Table 2-72)

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy (Full option) or Capacity Only	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Full Option: Energy payment based on submitted higher of “minimum dispatch price” and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments. Capacity only: No energy payments	Energy payment based on submitted higher of “minimum dispatch price” and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 2-22 Demand Response revenue by market: Calendar years 2002 through 2010 and January through March 2011 (See 2010 SOM, Figure 2-22)



Economic Program

Table 2-75 Economic Program registration on peak load days: Calendar years 2002 to 2010 and January through March 2011 (See 2010 SOM, Table 2-73)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
24-Jan-11	1,600	2,445.2

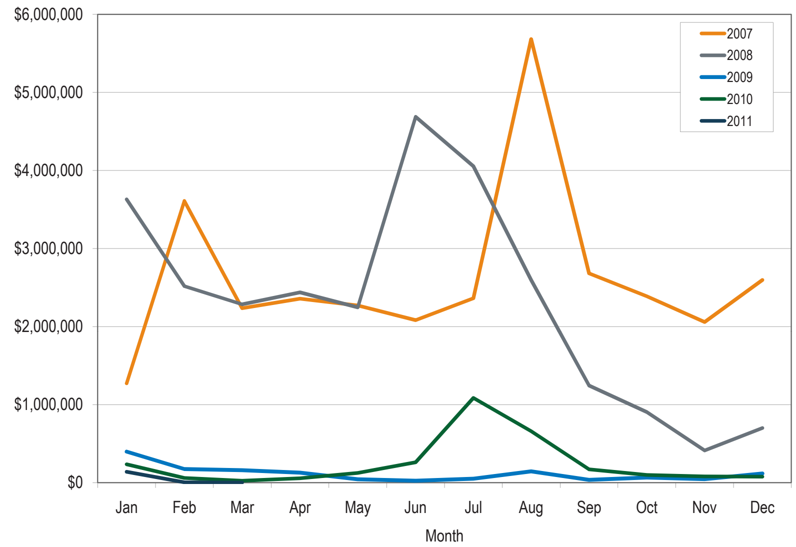
Table 2-76 Economic Program registrations on the last day of the month: January 2008 through March 2011 (See 2010 SOM, Table 2-74)

	2008		2009		2010		2011	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,607	2,449
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,454
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,610	2,537
Apr	5,016	3,197	2,582	3,242	1,849	2,587		
May	5,069	3,588	1,250	2,860	1,875	2,819		
Jun	3,112	3,014	1,265	2,461	813	1,608		
Jul	4,542	3,165	1,265	2,445	1,192	2,159		
Aug	4,815	3,232	1,653	2,650	1,616	2,398		
Sep	4,836	3,263	1,879	2,727	1,609	2,447		
Oct	4,846	3,266	1,875	2,730	1,606	2,444		
Nov	4,851	3,271	1,874	2,730	1,605	2,444		
Dec	4,851	3,290	1,853	2,627	1,598	2,439		
Avg.	4,727	3,185	2,508	2,852	1,608	2,435		

Table 2-77 Distinct registrations and sites in the Economic Program: January 24, 2011[11] (See 2010 SOM, Table 2-75)

	Registrations	Sites	MW
AECO	31	42	14.2
AEP	50	56	157.4
AP	54	58	186.5
BGE	57	76	476.4
ComEd	540	1,255	325.5
DAY	9	9	10.9
DLCO	54	59	86.4
Dominion	129	129	434.2
DPL	45	60	101.0
JCPL	47	85	108.0
Met-Ed	59	62	59.3
PECO	215	297	155.1
PENELEC	56	63	60.1
Pepco	37	39	33.5
PPL	135	164	180.3
PSEG	80	201	55.7
RECO	2	7	0.7
Total	1,600	2,662	2,445.2

Figure 2-23 Economic Program payments by month: Calendar years 2007[12] through 2010 and January through March 2011 (See 2010 SOM, Figure 2-23)



11 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of Table 2-77 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

12 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-23 do not include these incentive payments.

Table 2-78 PJM Economic Program participation by zone: January through March 2010 and 2011 (See 2010 SOM, Table 2-78)

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$25	$0	(100%)	0.2	0.0	(100%)
AEP	$0	$0	0%	0.0	0.0	0%
AP	$16,202	$6,020	(63%)	1,197.3	120.5	(90%)
BGE	$0	$0	0%	0.0	0.0	0%
ComEd	$10,986	$0	(100%)	370.2	0.0	(100%)
DAY	$0	$0	0%	0.0	0.0	0%
DLCO	$0	$44	0%	0.0	1.9	0%
Dominion	$213,189	$85,988	(60%)	3,779.3	817.8	(78%)
DPL	$0	$0	0%	0.0	0.0	0%
JCPL	$752	$0	(100%)	10.4	0.0	(100%)
Met-Ed	$16	$0	(100%)	1.5	0.0	(100%)
PECO	$70,000	$53,561	(23%)	2,372.9	1,203.5	(49%)
PENELEC	$156	$0	(100%)	1.1	0.0	(100%)
Pepco	$395	$0	(100%)	11.5	0.0	(100%)
PPL	$9,927	$0	(100%)	394.4	1.6	(100%)
PSEG	$0	$0	0%	0.0	0.0	0%
RECO	$0	$0	0%	0.0	0.0	0%
Total	$321,648	$145,613	(55%)	8,139	2,145.3	(74%)

Table 2-79 Settlement days submitted by month in the Economic Program: Calendar years 2008 through 2010 and January through March 2011 (See 2010 SOM, Table 2-79)

Month	2008	2009	2010	2011
Jan	2,916	1,264	1,415	565
Feb	2,811	654	546	148
Mar	2,818	574	411	82
Apr	3,406	337	338	
May	3,336	918	673	
Jun	3,184	2,727	1,221	
Jul	3,339	2,879	3,007	
Aug	3,848	3,760	2,158	
Sep	3,264	2,570	660	
Oct	1,977	2,361	699	
Nov	1,105	2,321	672	
Dec	986	1,240	894	
Total	32,990	21,605	12,694	795

Table 2-80 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2010 and January through March 2011 (See 2010 SOM, Table 2-80)

	2008		2009		2010		2011	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	162	5	40
Feb	13	243	12	129	9	92	6	29
Mar	11	216	11	149	7	124	3	15
Apr	12	208	9	76	5	77		
May	12	233	9	201	6	140		
Jun	17	317	20	231	11	152		
Jul	16	295	21	183	18	243		
Aug	17	306	15	400	14	302		
Sep	17	312	11	181	11	97		
Oct	13	226	11	93	8	37		
Nov	14	208	9	143	7	40		
Dec	13	193	10	160	7	46		
Total Distinct Active	24	522	25	747	24	438	6	56

Table 2-81 Hourly frequency distribution of Economic Program MWh reductions and credits: January through March 2011 (See 2010 SOM, Table 2-81)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	6	0.26%	6	0.26%	$105	0.07%	$105	0.07%
2	6	0.30%	12	0.56%	$193	0.13%	$298	0.20%
3	12	0.57%	24	1.13%	$619	0.43%	$917	0.63%
4	4	0.19%	28	1.32%	$61	0.04%	$978	0.67%
5	8	0.38%	36	1.70%	$51	0.03%	$1,028	0.71%
6	35	1.62%	71	3.32%	$721	0.50%	$1,750	1.20%
7	332	15.47%	403	18.78%	$23,812	16.35%	$25,562	17.55%
8	503	23.44%	906	42.22%	$53,174	36.52%	$78,736	54.07%
9	280	13.07%	1,186	55.29%	$22,654	15.56%	$101,390	69.63%
10	169	7.86%	1,355	63.15%	$9,190	6.31%	$110,580	75.94%
11	121	5.65%	1,476	68.80%	$4,550	3.13%	$115,131	79.07%
12	97	4.52%	1,573	73.32%	$2,128	1.46%	$117,258	80.53%
13	64	3.00%	1,637	76.32%	$1,473	1.01%	$118,731	81.54%
14	26	1.22%	1,663	77.54%	$305	0.21%	$119,036	81.75%
15	38	1.79%	1,702	79.33%	$931	0.64%	$119,968	82.39%
16	52	2.40%	1,753	81.73%	$882	0.61%	$120,850	82.99%
17	109	5.07%	1,862	86.80%	$2,199	1.51%	$123,049	84.50%
18	104	4.84%	1,966	91.64%	$8,960	6.15%	$132,009	90.66%
19	112	5.21%	2,078	96.85%	$11,243	7.72%	$143,252	98.38%
20	20	0.92%	2,097	97.77%	$1,142	0.78%	$144,394	99.16%
21	17	0.80%	2,115	98.57%	$646	0.44%	$145,040	99.61%
22	15	0.70%	2,130	99.26%	$408	0.28%	$145,448	99.89%
23	11	0.49%	2,140	99.76%	$113	0.08%	$145,561	99.96%
24	5	0.24%	2,145	100.00%	$52	0.04%	$145,613	100.00%

Table 2-82 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through March 2011 (See 2010 SOM, Table 2-82)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	6	0.28%	6	0.28%	$18	0.01%	$18	0.01%
$25 to $50	535	24.92%	541	25.20%	$8,211	5.64%	$8,229	5.65%
$50 to $75	506	23.57%	1,046	48.77%	$14,602	10.03%	$22,831	15.68%
$75 to $100	180	8.38%	1,226	57.15%	$9,976	6.85%	$32,807	22.53%
$100 to $125	40	1.87%	1,266	59.02%	$2,712	1.86%	$35,519	24.39%
$125 to $150	310	14.45%	1,576	73.48%	$27,162	18.65%	$62,680	43.05%
$150 to $200	327	15.24%	1,903	88.71%	$38,838	26.67%	$101,519	69.72%
$200 to $250	158	7.38%	2,061	96.09%	$27,623	18.97%	$129,142	88.69%
$250 to $300	64	2.99%	2,126	99.08%	$12,487	8.58%	$141,629	97.26%
> $300	20	0.92%	2,145	100.00%	$3,984	2.74%	$145,613	100.00%

Emergency Program

Load Management Program

Table 2-83 Zonal monthly capacity credits: January through March 2011 (See 2010 SOM, Table 2-85)

Zone	January	February	March	Total
AECO	$515,251	$465,388	$515,251	$1,495,889
AEP	$7,718,744	$6,971,769	$7,718,744	$22,409,257
APS	$4,272,819	$3,859,321	$4,272,819	$12,404,959
BGE	$5,039,828	$4,552,103	$5,039,828	$14,631,758
ComEd	$8,156,971	$7,367,587	$8,156,971	$23,681,529
DAY	$1,151,545	$1,040,105	$1,151,545	$3,343,196
DLCO	$1,118,544	$4,920,317	$1,118,544	$7,157,405
Dominion	$5,447,494	$982,920	$5,447,494	$11,877,908
DPL	$1,088,233	$1,010,298	$1,088,233	$3,186,764
JCPL	$1,301,034	$1,175,128	$1,301,034	$3,777,197
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$3,498,646
PECO	$2,826,229	$2,552,723	$2,826,229	$8,205,180
PENELEC	$1,827,610	$1,650,744	$1,827,610	$5,305,963
Pepco	$1,307,359	$1,180,840	$1,307,359	$3,795,557
PPL	$4,115,164	$3,716,922	$4,115,164	$11,947,251
PSEG	$2,536,813	$2,291,315	$2,536,813	$7,364,941
RECO	$9,266	$8,369	$9,266	$26,902
Total	$49,637,993	$44,834,317	$49,637,993	$144,110,303

SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance in the first three months of 2011. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Highlights

- 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.

- 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.

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

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.

Recommendations

- 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.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

In the first three months of 2011, total net revenues were generally higher than in the same period in 2010 for the CT and CC technologies, and generally lower for the CP technology. While the results varied by zone, energy net revenues in all but one zone for the CT and in all zones for the CC technology showed an increase compared to the same period in 2010 while energy net revenues showed a decrease in all but three zones for the CP technology, reflecting the higher spread between LMP and the cost of natural gas compared to the spread between LMP and the cost of coal. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

For the new entrant CT, all zones but BGE and Pepco had higher total net revenue in first three months of 2011 compared to the same period in 2010 (Table 3-7). For the new entrant CT, all zones but DLCO had higher energy net revenue. Ten zones had slightly lower capacity revenues and two zones had significantly lower capacity revenues, while five zones had higher capacity revenues.[1] The 2010/2011 Base Residual Auction (BRA) cleared with a single price across the entire market which was a significant reduction in price separation by location than prior BRAs and at a higher price for the RTO Locational Deliverability Area (LDA) than previous BRAs. As a result, zones that previously cleared in constrained LDAs saw slight decreases or, in the case of SWMAAC, significant decreases, in capacity revenue available for the first three months of 2011, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The DLCO control zone had a decrease in energy net revenues, which was more than offset by higher capacity revenues, resulting in an increase in total net revenue. The BGE and Pepco zones, which previously cleared in the SWMAAC LDA for the 2009/2010 delivery year, had a lower clearing price associated with the unconstrained RTO LDA for the 2010/2011 BRA. The decreases in capacity revenue in BGE and Pepco were not offset by increases in energy net revenue, leading to decreases in total net revenue in both zones.

For the new entrant CC, all zones but BGE, PSEG and RECO had higher total net revenue in the first three months of 2011 compared to the same period in 2010 (Table 3-9). For the new entrant CC, all zones showed an increase in energy net revenue. For BGE, PSEG and RECO, higher energy net revenue did not offset decreases in capacity revenues.

1 This section discusses capacity revenues to new and existing units based on the clearing prices in Base Residual Auctions (BRA). It is not intended to reflect actual revenues associated with RPM.

For the new entrant coal plant (CP), all zones but AEP, AP and DAY had lower total net revenue through the first three months of 2011 compared to the same period in 2010 (Table 3-11). For the CP, all zones but AEP, AP, and BGE showed a decrease in energy net revenues. For AEP, higher capacity revenues in addition to higher energy net revenues contributed to an increase in total net revenues. For AP, higher energy revenues were only partially offset by lower capacity revenues. The BGE zone showed slightly higher energy net revenue which was more than offset by lower capacity revenue. The DAY zone showed slightly lower energy net revenue which was more than offset by higher capacity revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through March 31, 2011, PJM installed capacity resources fell slightly from 166,410.2 MW on January 1 to 166,292.2 MW on March 31, a decrease of 118.0 MW or 0.1 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of March 31, 2011, 40.9 percent was coal; 28.7 percent was gas; 18.3 percent was nuclear; 6.5 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, 0.3 percent was wind, and 0.0 percent was solar.

- **Generation Fuel Mix.** In January through March 2011, coal provided 47.7 percent, nuclear 35.7 percent, gas 12.0 percent, oil 0.1 percent, hydroelectric 1.9 percent, solid waste 0.7 percent and wind 1.8 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in the first three months of 2011.** PJM did not declare a scarcity event in the first three months of 2011.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole payments, operating reserve credits are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying the operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in the first three months of 2011.** Operating reserve charges increased 14.9 percent in the first three months of 2011 compared to the first three months of 2011. Reliability credits increased $7,922,157 in the first three months of 2011 compared to the first three months of 2010, and deviation credits increased $9,248,673.

  The overall increase in operating reserve charges in 2011 is comprised of a 5.5 percent decrease in day-ahead operating reserve charges, a 0.1 percent increase in synchronous condensing charges and a 5.4 percent increase in balancing operating reserve charges.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

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

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

In the first three months of 2011, energy market revenues were generally higher for new entrant combustion turbines and combined cycles, both using natural gas, as energy market prices increased in most zones, particularly MAAC zones, and, the average delivered price of natural gas decreased in most zones. Energy market net revenues for new entrant coal plants were lower in all zones except for AEP and AP as the average delivered price of low sulfur coal increased more than energy market prices in most zones. In AEP and AP, while average energy market prices changed slightly, increasing in AEP and decreasing in AP, the delivered price of coal in both zones decreased compared to the same period in 2010.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units. With the exception of

DLCO, all zones show a higher frequency of hours with Real-Time LMP greater than $200 and more volatile Real-Time hourly LMPs through the first three months of 2011 compared to 2010. The PPL zone showed fifteen hours of Real-Time LMP greater than $200 through the first three months of 2011 compared to two hours in the same period of 2010, while the DLCO zone showed one hour through the first three months of 2011 compared to fifteen hours in the same period for 2010. As a result, the average increase in energy net revenue for a new entrant CT was 98 percent, and the increase in energy net revenue for PPL was 444 percent, while the decrease in DLCO energy net revenue was 47 percent.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of total costs for existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The Capacity Market is also a significant source of net revenue to cover the fixed costs of investing in new peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining Capacity Market prices are higher than actual energy net revenues, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. In addition, coal plants face the most severe operational constraints, which can lead to operating during hours when the Real-Time LMP is less than the incremental costs of generation, decreasing energy revenues. In the first three months of 2011, coal prices increased significantly in most zones while the average Real-Time LMP increased only slightly in some zones and decreased in other zones, leading to lower energy revenues for coal plants. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. However, in 2011, compared to the 2010, as the average delivered price of coal increased while the average delivery price of natural gas decreased in most locations, coal plants received less inframarginal revenues when during hours when CCs and CTs ran in the first three months of 2011, which contributed to a decrease in the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2011 (See 2010 SOM, Table 3-3)

	Delivery Year 2010/2011			Delivery Year 2011/2012			RPM Revenue
Zone	LDA	$/MW-Day	$/MW in 2011	LDA	$/MW-Day	$/MW in 2011	2011 (Jan - Dec) $/MW
AECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
AEP	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
AP	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
BGE	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
ComEd	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DAY	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DLCO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Dominion	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
DPL	DPL South/RTO	$178.57	$26,964	RTO	$110.00	$23,540	$50,504
JCPL	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Met-Ed	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PENELEC	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
Pepco	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PPL	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PSEG	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
RECO	RTO	$174.29	$26,318	RTO	$110.00	$23,540	$49,858
PJM	NA	$174.42	$26,338	NA	$110.00	$23,540	$49,878

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-4)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$17,219	$15,686	(9%)
AEP	$9,184	$15,686	71%
AP	$17,219	$15,686	(9%)
BGE	$21,360	$15,686	(27%)
ComEd	$9,184	$15,686	71%
DAY	$9,184	$15,686	71%
DLCO	$9,184	$15,686	71%
Dominion	$9,184	$15,686	71%
DPL	$17,219	$16,071	(7%)
JCPL	$17,219	$15,686	(9%)
Met-Ed	$17,219	$15,686	(9%)
PECO	$17,219	$15,686	(9%)
PENELEC	$17,219	$15,686	(9%)
Pepco	$21,360	$15,686	(27%)
PPL	$17,219	$15,686	(9%)
PSEG	$17,219	$15,686	(9%)
RECO	$17,219	$15,686	(9%)
PJM	$13,902	$15,698	13%

New Entrant Net Revenues

Table 3-3 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year):[2] Net revenue for January through March 2010 and 2011 (See 2010 SOM, Table 3-5)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$2,018	$6,314	213%
AEP	$988	$1,916	94%
AP	$2,225	$5,420	144%
BGE	$3,262	$4,969	52%
ComEd	$446	$1,113	150%
DAY	$802	$2,180	172%
DLCO	$3,897	$2,069	(47%)
Dominion	$4,180	$4,219	1%
DPL	$2,518	$4,296	71%
JCPL	$2,117	$5,946	181%
Met-Ed	$1,892	$4,671	147%
PECO	$1,873	$4,851	159%
PENELEC	$942	$5,128	444%
Pepco	$6,995	$11,579	66%
PPL	$1,784	$6,905	287%
PSEG	$2,235	$4,032	80%
RECO	$1,422	$2,895	104%
PJM	$2,329	$4,618	98%

2 The energy net revenues presented for PJM for 2010 and 2011 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for PJM represent the simple average energy net revenue.

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through March 2010 and 2011 (See 2010 SOM, Table 3-6)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$10,993	$18,454	68%
AEP	$5,023	$9,928	98%
AP	$10,097	$18,953	88%
BGE	$12,579	$14,271	13%
ComEd	$2,816	$5,281	88%
DAY	$4,710	$10,004	112%
DLCO	$7,809	$9,385	20%
Dominion	$12,787	$13,541	6%
DPL	$11,190	$14,567	30%
JCPL	$10,858	$17,557	62%
Met-Ed	$9,943	$14,401	45%
PECO	$10,255	$15,903	55%
PENELEC	$6,745	$18,215	170%
Pepco	$19,370	$28,232	46%
PPL	$9,352	$17,131	83%
PSEG	$10,709	$12,148	13%
RECO	$7,581	$8,555	13%
PJM	$9,577	$14,501	51%

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through March 2010 and 2011 (See 2010 SOM, Table 3-7)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$38,430	$32,048	(17%)
AEP	$20,790	$22,697	9%
AP	$27,693	$34,176	23%
BGE	$17,367	$19,881	14%
ComEd	$33,265	$25,120	(24%)
DAY	$25,205	$22,116	(12%)
DLCO	$27,038	$7,006	(74%)
Dominion	$38,203	$29,635	(22%)
DPL	$39,554	$31,086	(21%)
JCPL	$37,869	$30,873	(18%)
Met-Ed	$36,661	$25,458	(31%)
PECO	$37,527	$28,063	(25%)
PENELEC	$31,838	$28,726	(10%)
Pepco	$40,850	$29,285	(28%)
PPL	$31,337	$28,491	(9%)
PSEG	$33,301	$21,927	(34%)
RECO	$35,558	$23,197	(35%)
PJM	$32,499	$25,870	(20%)

New Entrant Combustion Turbine

Table 3-6 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-8)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$2,329	$4,618	98%
Capacity	$12,678	$14,315	13%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$596	$596	0%
Total	$15,603	$19,529	25%

Table 3-7 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-9)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$18,316	$21,215	16%
AEP	$9,959	$16,817	69%
AP	$18,522	$20,320	10%
BGE	$23,336	$19,869	(15%)
ComEd	$9,416	$16,013	70%
DAY	$9,773	$17,080	75%
DLCO	$12,867	$16,970	32%
Dominion	$13,151	$19,119	45%
DPL	$18,816	$19,547	4%
JCPL	$18,415	$20,847	13%
Met-Ed	$18,190	$19,572	8%
PECO	$18,171	$19,751	9%
PENELEC	$17,240	$20,028	16%
Pepco	$27,069	$26,479	(2%)
PPL	$18,082	$21,805	21%
PSEG	$18,533	$18,932	2%
RECO	$17,720	$17,795	0%
PJM	$15,603	$19,529	25%

New Entrant Combined Cycle

Table 3-8 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-10)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$9,577	$14,501	51%
Capacity	$13,395	$15,125	13%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$800	$800	0%
Total	$23,772	$30,426	28%

Table 3-9 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-11)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$28,383	$34,367	21%
AEP	$14,671	$25,841	76%
AP	$27,487	$34,866	27%
BGE	$33,959	$30,184	(11%)
ComEd	$12,464	$21,195	70%
DAY	$14,358	$25,917	80%
DLCO	$17,457	$25,298	45%
Dominion	$22,435	$29,454	31%
DPL	$28,580	$30,851	8%
JCPL	$28,247	$33,470	18%
Met-Ed	$27,333	$30,314	11%
PECO	$27,645	$31,816	15%
PENELEC	$24,135	$34,128	41%
Pepco	$40,750	$44,145	8%
PPL	$26,742	$33,044	24%
PSEG	$28,099	$28,061	(0%)
RECO	$24,971	$24,468	(2%)
PJM	$23,772	$30,426	28%

New Entrant Coal Plant

Table 3-10 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-12)

	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
Energy	$32,499	$25,870	(20%)
Capacity	$12,537	$14,157	13%
Synchronized	$0	$0	0%
Regulation	$46	$5	(90%)
Reactive	$446	$446	0%
Total	$45,528	$40,477	(11%)

Table 3-11 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-13)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$54,439	$46,643	(14%)
AEP	$29,565	$37,298	26%
AP	$43,702	$48,784	12%
BGE	$37,095	$34,472	(7%)
ComEd	$42,095	$39,740	(6%)
DAY	$33,994	$36,718	8%
DLCO	$35,836	$21,598	(40%)
Dominion	$46,966	$44,227	(6%)
DPL	$55,588	$46,029	(17%)
JCPL	$53,880	$45,465	(16%)
Met-Ed	$52,672	$40,050	(24%)
PECO	$53,536	$42,654	(20%)
PENELEC	$47,878	$43,326	(10%)
Pepco	$60,587	$43,877	(28%)
PPL	$47,341	$43,083	(9%)
PSEG	$49,315	$36,518	(26%)
RECO	$51,573	$37,788	(27%)
PJM	$45,528	$40,477	(11%)

New Entrant Day-Ahead Net Revenues

Table 3-12 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-14)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$615	$3,623	489%
AEP	$109	$480	339%
AP	$774	$3,421	342%
BGE	$1,016	$3,154	210%
ComEd	$4	$75	1,622%
DAY	$23	$392	1,575%
DLCO	$320	$625	95%
Dominion	$2,354	$2,861	22%
DPL	$598	$3,088	416%
JCPL	$574	$4,267	643%
Met-Ed	$562	$3,023	438%
PECO	$579	$3,806	558%
PENELEC	$301	$3,245	978%
Pepco	$5,618	$10,519	87%
PPL	$550	$4,841	781%
PSEG	$302	$2,363	683%
RECO	$214	$1,619	656%
PJM	$854	$3,024	254%

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-15)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$11,513	$19,459	69%
AEP	$4,609	$9,733	111%
AP	$10,298	$19,953	94%
BGE	$13,401	$15,365	15%
ComEd	$1,969	$3,746	90%
DAY	$3,677	$9,359	155%
DLCO	$5,639	$8,623	53%
Dominion	$15,299	$14,544	(5%)
DPL	$9,945	$16,793	69%
JCPL	$11,720	$20,396	74%
Met-Ed	$10,287	$16,277	58%
PECO	$10,709	$18,740	75%
PENELEC	$8,349	$19,065	128%
Pepco	$22,395	$30,361	36%
PPL	$9,582	$18,580	94%
PSEG	$9,445	$13,828	46%
RECO	$7,712	$10,245	33%
PJM	$9,797	$15,592	59%

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-16)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	Percent Change
AECO	$43,894	$34,967	(20%)
AEP	$22,087	$23,257	5%
AP	$30,595	$35,628	16%
BGE	$21,278	$21,131	(1%)
ComEd	$35,512	$24,778	(30%)
DAY	$26,139	$22,352	(14%)
DLCO	$27,126	$6,081	(78%)
Dominion	$45,952	$32,824	(29%)
DPL	$44,309	$36,205	(18%)
JCPL	$44,227	$34,709	(22%)
Met-Ed	$42,674	$28,388	(33%)
PECO	$43,596	$32,626	(25%)
PENELEC	$37,272	$30,006	(19%)
Pepco	$48,512	$31,807	(34%)
PPL	$37,298	$31,193	(16%)
PSEG	$38,041	$25,206	(34%)
RECO	$43,435	$30,047	(31%)
PJM	$37,173	$28,306	(24%)

Table 3-15 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through March 2011 (See 2010 SOM, Table 3-17)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
2010	$36,925	$22,981	$13,944	38%
2011 (Jan - Mar)	$4,618	$3,024	$1,594	35%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through March 2011 (See 2010 SOM, Table 3-18)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
2010	$88,275	$78,976	$9,299	11%
2011 (Jan - Mar)	$14,501	$15,592	($1,091)	(8%)

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2010 and January through March 2011 (See 2010 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
2010	$128,990	$126,772	$2,218	2%
2011 (Jan - Mar)	$25,870	$28,306	($2,436)	(9%)

Net Revenue Adequacy

Table 3-18 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)): Calendar years 2005 through 2010 (See 2010 SOM, Table 3-20)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost	2010 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705	$131,044
CC	$93,549	$99,230	$143,600	$171,361	$173,174	$175,250
CP	$208,247	$267,792	$359,750	$492,780	$446,550	$465,455

New Entrant Combustion Turbine

Table 3-19 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-22)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$18,316	$21,215	$131,044	14%	16%
AEP	$9,959	$16,817	$131,044	8%	13%
AP	$18,522	$20,320	$131,044	14%	16%
BGE	$23,336	$19,869	$131,044	18%	15%
ComEd	$9,416	$16,013	$131,044	7%	12%
DAY	$9,773	$17,080	$131,044	7%	13%
DLCO	$12,867	$16,970	$131,044	10%	13%
Dominion	$13,151	$19,119	$131,044	10%	15%
DPL	$18,816	$19,547	$131,044	14%	15%
JCPL	$18,415	$20,847	$131,044	14%	16%
Met-Ed	$18,190	$19,572	$131,044	14%	15%
PECO	$18,171	$19,751	$131,044	14%	15%
PENELEC	$17,240	$20,028	$131,044	13%	15%
Pepco	$27,069	$26,479	$131,044	21%	20%
PPL	$18,082	$21,805	$131,044	14%	17%
PSEG	$18,533	$18,932	$131,044	14%	14%
RECO	$17,720	$17,795	$131,044	14%	14%
PJM	$15,603	$19,529	$131,044	12%	15%

Figure 3-1 New entrant CT real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): (See 2010 SOM, Figure 3-3)

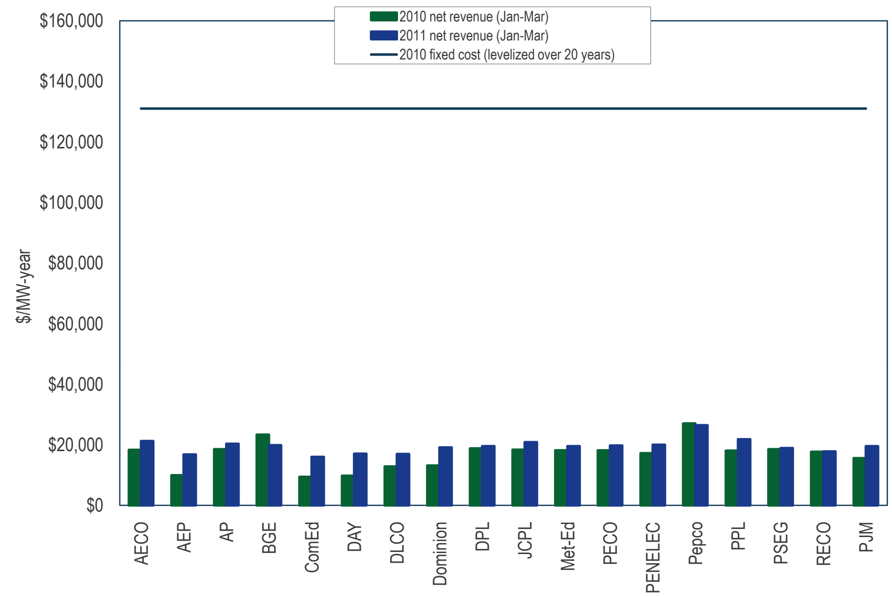
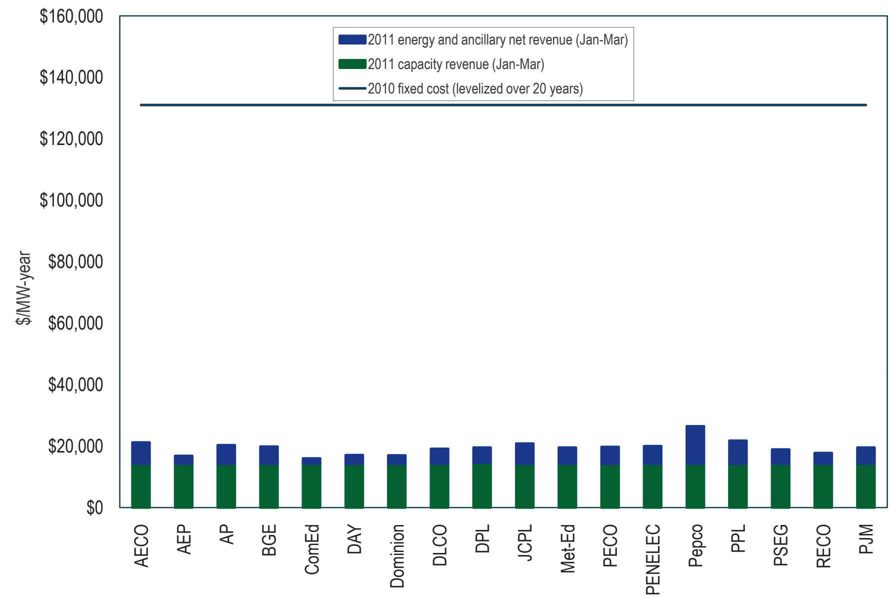


Figure 3-2 New entrant CT zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-4)



New Entrant Combined Cycle

Table 3-20 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-24)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$28,383	$34,367	$175,250	16%	20%
AEP	$14,671	$25,841	$175,250	8%	15%
AP	$27,487	$34,866	$175,250	16%	20%
BGE	$33,959	$30,184	$175,250	19%	17%
ComEd	$12,464	$21,195	$175,250	7%	12%
DAY	$14,358	$25,917	$175,250	8%	15%
DLCO	$17,457	$25,298	$175,250	10%	14%
Dominion	$22,435	$29,454	$175,250	13%	17%
DPL	$28,580	$30,851	$175,250	16%	18%
JCPL	$28,247	$33,470	$175,250	16%	19%
Met-Ed	$27,333	$30,314	$175,250	16%	17%
PECO	$27,645	$31,816	$175,250	16%	18%
PENELEC	$24,135	$34,128	$175,250	14%	19%
Pepco	$40,750	$44,145	$175,250	23%	25%
PPL	$26,742	$33,044	$175,250	15%	19%
PSEG	$28,099	$28,061	$175,250	16%	16%
RECO	$24,971	$24,468	$175,250	14%	14%
PJM	$23,772	$30,426	$175,250	14%	17%

Figure 3-3 New entrant CC real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Figure 3-6)

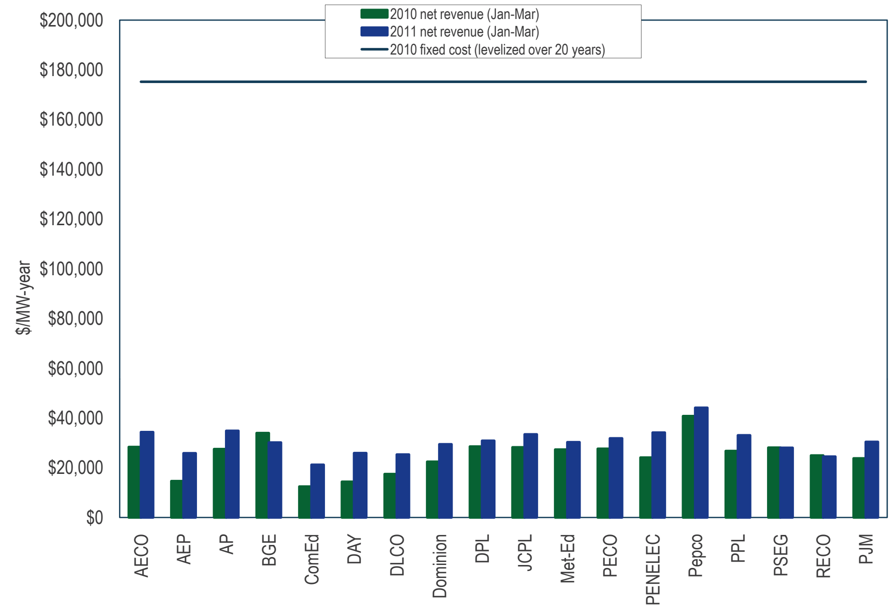
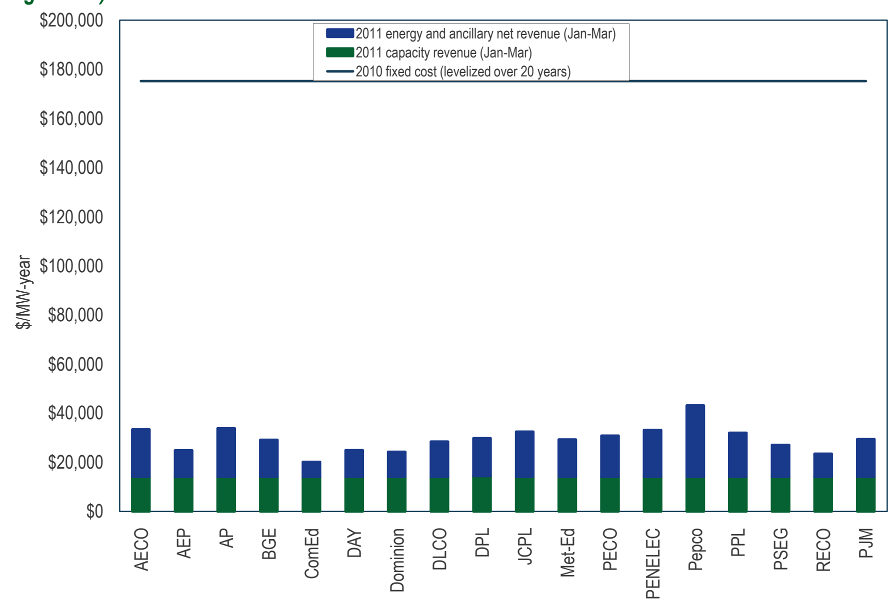


Figure 3-4 New entrant CC zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-7)



New Entrant Coal Plant

Table 3-21 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Table 3-26)

Zone	2010 (Jan - Mar)	2011 (Jan - Mar)	20-Year Levelized Fixed Cost	2010 Percent Recovery	2011 Percent Recovery
AECO	$54,439	$46,643	$465,455	12%	10%
AEP	$29,565	$37,298	$465,455	6%	8%
AP	$43,702	$48,784	$465,455	9%	10%
BGE	$37,095	$34,472	$465,455	8%	7%
ComEd	$42,095	$39,740	$465,455	9%	9%
DAY	$33,994	$36,718	$465,455	7%	8%
DLCO	$35,836	$21,598	$465,455	8%	5%
Dominion	$46,966	$44,227	$465,455	10%	10%
DPL	$55,588	$46,029	$465,455	12%	10%
JCPL	$53,880	$45,465	$465,455	12%	10%
Met-Ed	$52,672	$40,050	$465,455	11%	9%
PECO	$53,536	$42,654	$465,455	12%	9%
PENELEC	$47,878	$43,326	$465,455	10%	9%
Pepco	$60,587	$43,877	$465,455	13%	9%
PPL	$47,341	$43,083	$465,455	10%	9%
PSEG	$49,315	$36,518	$465,455	11%	8%
RECO	$51,573	$37,788	$465,455	11%	8%
PJM	$45,528	$40,477	$465,455	10%	9%

Figure 3-5 New entrant CP real-time net revenue for January through March 2010 and 2011 and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year): January through March 2010 and 2011 (See 2010 SOM, Figure 3-9)

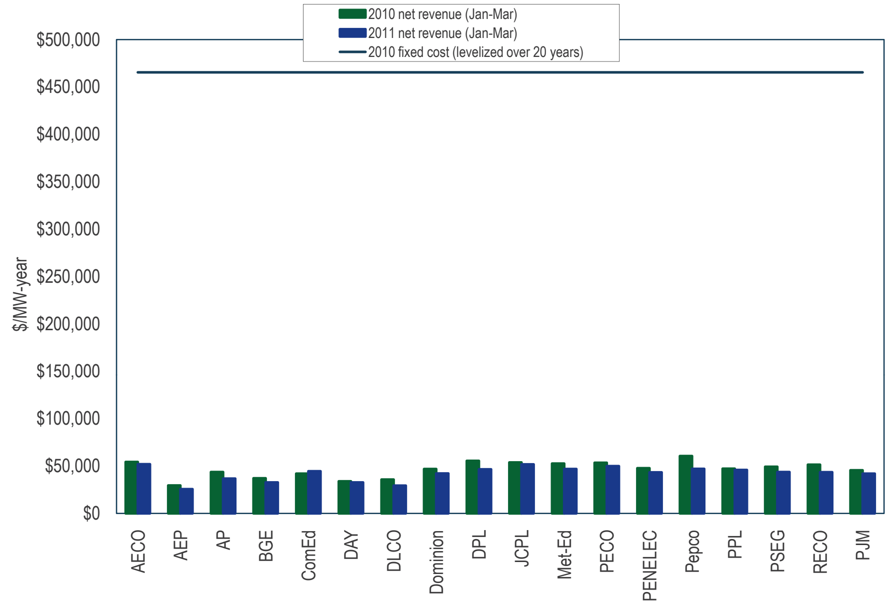
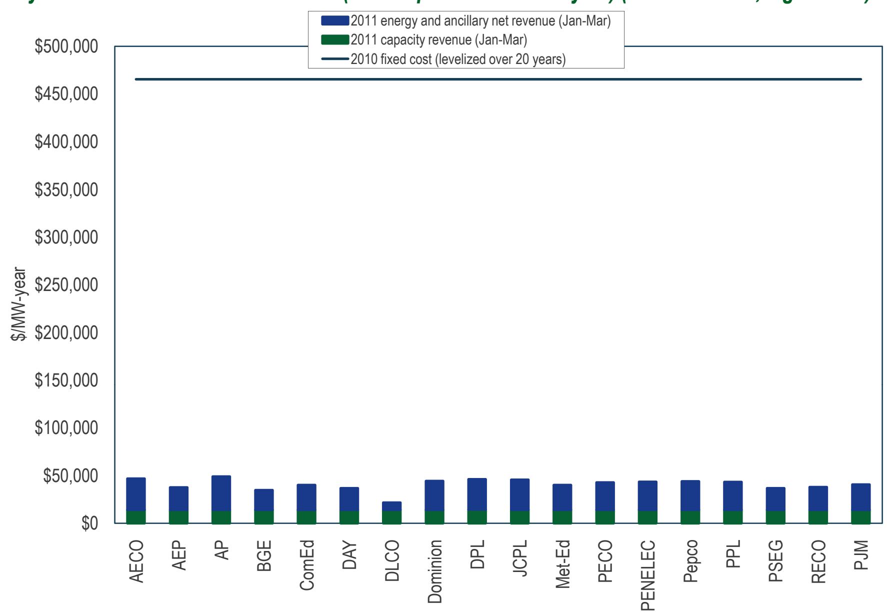


Figure 3-6 New entrant CP zonal real-time January through March 2011 net revenue by market and 20-year levelized fixed cost as of 2010 (Dollars per installed MW-year) (See 2010 SOM, Figure 3-10)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-22 Table 3-22 PJM installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2011 (See 2010 SOM, Table 3-42)

	1-Jan-11		31-Jan-11		28-Feb-11		31-Mar-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,986.0	40.9%	67,966.1	40.8%	67,979.2	40.9%
Gas	47,736.6	28.7%	47,735.2	28.7%	47,726.0	28.7%	47,750.0	28.7%
Hydroelectric	7,954.5	4.8%	8,020.5	4.8%	8,018.4	4.8%	8,018.4	4.8%
Nuclear	30,552.2	18.4%	30,459.2	18.3%	30,732.2	18.5%	30,457.2	18.3%
Oil	10,949.5	6.6%	10,854.5	6.5%	10,854.1	6.5%	10,854.1	6.5%
Solar	0.0	0.0%	1.9	0.0%	1.9	0.0%	1.9	0.0%
Solid waste	680.1	0.4%	680.1	0.4%	680.1	0.4%	680.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	551.3	0.3%	551.3	0.3%
Total	166,410.2	100.0%	166,288.7	100.0%	166,530.1	100.0%	166,292.2	100.0%

Energy Production by Fuel Source

Table 3-23 PJM generation (By fuel source (GWh)): January through March 2010 and 2011[3] (See 2010 SOM, Table 3-43)

	2010 (Jan-Mar)		2011 (Jan-Mar)		Change
	GWh	Percent	GWh	Percent	in Output
Coal	98,126.2	53.8%	87,182.8	47.7%	(11.2%)
Standard Coal	95,374.4	52.3%	84,234.9	46.1%	0.0%
Waste Coal	2,751.9	1.5%	2,947.9	1.6%	0.0%
Nuclear	63,428.4	34.8%	65,194.7	35.7%	2.8%
Gas	13,000.5	7.1%	21,973.5	12.0%	69.0%
Natural Gas	12,615.9	6.9%	21,552.9	11.8%	70.8%
Landfill Gas	384.6	0.2%	420.6	0.2%	9.4%
Biomass Gas	0.1	0.0%	0.0	0.0%	(70.5%)
Hydroelectric	4,266.2	2.3%	3,524.1	1.9%	(17.4%)
Wind	2,158.3	1.2%	3,220.9	1.8%	49.2%
Waste	1,199.0	0.7%	1,257.9	0.7%	4.9%
Solid Waste	931.7	0.5%	932.8	0.5%	0.1%
Miscellaneous	267.3	0.1%	325.1	0.2%	21.6%
Oil	113.4	0.1%	228.7	0.1%	101.7%
Heavy Oil	80.6	0.0%	190.1	0.1%	135.9%
Light Oil	28.6	0.0%	35.4	0.0%	23.8%
Diesel	4.0	0.0%	2.4	0.0%	(40.7%)
Kerosene	0.2	0.0%	0.9	0.0%	302.7%
Jet Oil	0.0	0.0%	0.0	0.0%	(59.5%)
Solar	0.8	0.0%	7.0	0.0%	810.2%
Battery	0.1	0.0%	0.1	0.0%	12.5%
Total	182,293.0	100.0%	182,589.8	100.0%	0.2%

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

Table 3-24 PJM capacity factor (By unit type (GWh)); January through March 2010 and 2011 (New table)

	2010 (Jan-Mar)		2011 (Jan-Mar)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	4.5%	0.1	5.1%
Combined Cycle	11,870.7	24.5%	20,893.0	42.3%
Combustion Turbine	459.7	0.8%	483.1	0.8%
Diesel	346.6	22.9%	365.8	24.0%
Nuclear	63,428.4	93.8%	65,194.7	96.4%
Pumped Storage Hydro	1,741.2	14.7%	1,652.5	13.9%
Run of River Hydro	2,525.0	50.3%	1,871.7	37.3%
Solar	0.8	11.9%	7.0	13.1%
Steam	99,900.0	57.4%	89,005.6	51.1%
Wind	2,158.3	31.3%	3,220.9	34.5%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through March 2011[4] (See 2010 SOM, Table 3-44)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011 (Jan-Mar)	1,034

PJM Generation Queues

Table 3-26 Queue comparison (MW): March 31, 2011 vs. December 31, 2010 (See 2010 SOM, Table 3-44)

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	22,431	(2,947)	(12%)
2012	13,261	13,390	129	1%
2013	11,244	11,004	(240)	(2%)
2014	13,888	13,563	(325)	(2%)
2015	5,960	7,996	2,036	34%
2016	1,350	2,020	670	50%
2017	2,140	2,140	0	0%
2018	3,194	3,194	0	0%
Total	76,415	75,737	(678)	(1%)

4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-27 Capacity in PJM queues (MW): At March 31, 2011[5, 6] (See 2010 SOM, Table 3-46)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	15,833	20,478
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	1,155	21,461	23,102
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	160	2,336	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	3,978	4,482
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,678	1,346	471	4,077	7,572
P Expired 31-Jan-06	513	2,500	630	5,058	8,701
Q Expired 31-Jul-06	1,759	1,141	3,021	8,693	14,614
R Expired 31-Jan-07	4,887	649	1,225	15,994	22,755
S Expired 31-Jul-07	3,137	1,614	1,168	14,975	20,893
T Expired 31-Jan-08	11,399	623	750	14,845	27,617
U Expired 31-Jan-09	6,701	212	294	26,106	33,312
V Expired 31-Jan-10	12,387	70	244	4,218	16,918
W Expired 31-Jan-11	18,497	0	166	5,456	24,119
X Expires 31-Jan-12	3,927	0	0	0	3,927
Total	66,281	27,517	9,456	215,841	319,095

Table 3-28 Average project queue times (days): At March 31, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	782	602	0	4,420
In-Service	785	646	0	3,287
Suspended	2,431	735	890	3,849
Under Construction	1,139	917	0	4,370
Withdrawn	515	495	0	3,186

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At March 31, 2011 (See 2010 SOM, Table 3-48)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
AECO	0	1,255	775	17	0	0	1,006	665	2,139	5,856
AEP	0	1,845	580	7	170	84	166	2,482	13,475	18,809
AP	32	958	0	6	78	0	523	1,297	1,180	4,074
BGE	0	0	0	29	0	1,640	0	132	0	1,801
ComEd	20	1,080	1,038	84	23	750	49	1,366	15,612	20,021
DAY	0	0	0	2	112	0	60	12	1,440	1,626
DLCO	0	0	0	0	0	91	0	0	0	91
Dominion	32	1,960	595	21	3	1,774	134	302	1,640	6,461
DPL	0	309	109	0	0	0	208	43	645	1,313
JCPL	0	1,965	27	33	0	0	1,139	0	0	3,164
Met-Ed	23	1,760	7	23	0	24	150	0	0	1,987
PECO	2	663	27	17	0	510	26	0	0	1,246
PENELEC	0	0	65	15	0	0	132	90	930	1,232
Pepco	0	1,479	0	6	0	0	46	0	0	1,531
PPL	20	0	139	13	3	1,600	167	33	498	2,473
PSEG	0	2,490	1,077	3	0	50	307	105	20	4,051
Total	129	15,763	4,439	278	388	6,523	4,112	6,526	37,579	75,737

5 The *2011 Quarterly State of the Market Report for PJM: January through March* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2011[7] (See 2010 SOM, Table 3-49)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Total
EMAAC	2	6,681	2,015	71	0	560	2,686	813	2,804	15,631
SWMAAC	0	1,479	0	35	0	1,640	46	132	0	3,332
WMAAC	43	1,760	211	52	3	1,624	449	123	1,428	5,692
Non-MAAC	84	5,843	2,213	121	386	2,699	931	5,459	33,347	51,082
Total	129	15,763	4,439	278	388	6,523	4,112	6,526	37,579	75,737

Table 3-31 Existing PJM capacity: At March 31, 2011[8] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	Battery	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Wind	Total
AECO	0	0	608	23	0	0	0	1,264	8	1,902
AEP	0	4,355	3,668	57	1,005	2,106	0	21,568	1,053	33,811
AP	0	1,129	1,180	36	108	0	0	7,773	566	10,792
BGE	0	0	841	7	0	1,705	0	3,026	0	5,578
ComEd	0	1,814	7,129	111	0	10,376	0	6,791	1,945	28,165
DAY	0	0	1,364	52	0	0	1	3,572	0	4,989
DLCO	0	244	45	0	6	1,777	0	1,239	0	3,311
Dominion	0	3,173	3,853	161	3,558	3,494	0	8,484	0	22,723
DPL	0	1,117	1,755	96	0	0	0	1,919	0	4,887
External	0	974	1,574	0	70	439	0	9,470	185	12,712
JCPL	0	1,390	1,225	25	400	615	0	318	0	3,972
Met-Ed	0	2,000	406	23	20	805	0	890	0	4,143
PECO	1	2,552	836	7	1,642	4,509	3	2,129	0	11,679
PENELEC	0	0	287	39	505	0	0	6,834	555	8,219
Pepco	0	230	1,325	12	0	0	0	4,706	0	6,273
PPL	0	1,700	618	63	571	2,375	0	5,532	220	11,078
PSEG	0	2,921	2,860	0	5	3,553	58	2,535	0	11,932
Total	1	23,598	29,572	711	7,890	31,753	63	88,048	4,531	186,167

7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
8 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-32 PJM capacity (MW) by age: at March 31, 2011 (See 2010 SOM, Table 3-51)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 11	1	18,253	14,734	377	10	0	1,192	63	4,521	39,150
11 to 20	0	4,047	6,325	126	49	0	5,613	0	10	16,170
21 to 30	0	857	1,084	38	3,404	15,210	7,233	0	0	27,825
31 to 40	0	244	4,195	24	105	15,062	31,769	0	0	51,399
41 to 50	0	198	3,234	143	2,915	1,482	24,868	0	0	32,839
51 to 60	0	0	0	4	348	0	15,267	0	0	15,619
61 to 70	0	0	0	0	0	0	1,956	0	0	1,956
71 to 80	0	0	0	0	344	0	95	0	0	439
81 to 90	0	0	0	0	488	0	54	0	0	542
91 to 100	0	0	0	0	190	0	0	0	0	190
101 and over	0	0	0	0	37	0	0	0	0	37
Total	1	23,598	29,572	711	7,890	31,753	88,048	63	4,531	186,167

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (See 2010 SOM, Table 3-52)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	2	3	0.0%
	Combined Cycle	0	0.0%	7,980	23.2%	6,681	14,662	33.2%
	Combustion Turbine	955	12.2%	7,285	21.2%	2,015	8,344	18.9%
	Diesel	49	0.6%	150	0.4%	71	171	0.4%
	Hydroelectric	2,042	26.0%	2,047	6.0%	0	2,047	4.6%
	Nuclear	615	7.8%	8,676	25.2%	560	8,622	19.5%
	Solar	0	0.0%	61	0.2%	2,686	2,747	6.2%
	Steam	4,192	53.4%	8,164	23.8%	813	4,785	10.8%
	Wind	0	0.0%	8	0.0%	2,804	2,812	6.4%
	EMAAC Total	7,853	100.0%	34,372	100.0%	15,631	44,193	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	1,479	1,709	15.0%
	Combustion Turbine	540	14.2%	2,165	18.3%	0	1,625	14.3%
	Diesel	0	0.0%	19	0.2%	35	54	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	29.4%
	Solar	0	0.0%	0	0.0%	46	46	0.4%

Table 3-33 continued next page.

9 Percents shown in Table 3-33 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
	Steam	3,267	85.8%	7,732	65.2%	132	4,597	40.4%
	SWMAAC Total	3,807	100.0%	11,851	100.0%	3,332	11,377	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	43	43	0.2%
	Combined Cycle	0	0.0%	3,700	15.8%	1,760	5,460	24.1%
	Combustion Turbine	296	4.3%	1,310	5.6%	211	1,225	5.4%
	Diesel	35	0.5%	125	0.5%	52	141	0.6%
	Hydroelectric	444	6.5%	1,096	4.7%	3	1,098	4.8%
	Nuclear	0	0.0%	3,180	13.6%	1,624	4,804	21.2%
	Solar	0	0.0%	0	0.0%	449	449	2.0%
	Steam	6,042	88.6%	13,256	56.6%	123	7,336	32.4%
	Wind	0	0.0%	734	3.1%	1,428	2,162	9.5%
	WMAAC Total	6,817	100.0%	23,399	100.0%	5,692	22,675	100.0%
Non-MAAC	Battery	0	0.0%	0	0.0%	84	84	0.1%
	Combined Cycle	0	0.0%	11,688	10.0%	5,843	17,531	12.5%
	Combustion Turbine	709	2.6%	18,812	16.2%	2,213	20,316	14.5%
	Diesel	48	0.2%	418	0.4%	121	490	0.4%
	Hydroelectric	1,401	5.0%	4,747	4.1%	386	3,731	2.7%
	Nuclear	0	0.0%	18,192	15.6%	2,699	20,891	14.9%
	Solar	0	0.0%	1	0.0%	931	933	0.7%
	Steam	25,632	92.2%	58,896	50.6%	5,459	38,723	27.7%
	Wind	0	0.0%	3,699	3.2%	33,347	37,046	26.5%
	Non-MAAC Total	27,790	100.0%	116,453	100.0%	51,082	139,746	100.0%
All Areas	Total	46,267		186,076		75,737	217,990	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through March 2011 (See 2010 SOM, Table 3-53)[10]

Type of Resource	Capacity Factor	Total Run Hours	Peak Capacity Factor	Peak Run Hours	Installed Capacity (MW)
Energy-Only Resource	30.6%	34,711	N/A	N/A	1,160
Capacity Resource	35.6%	77,724	199.8%	9,102	3,371
All Units	34.5%	112,435	N/A	9,102	4,531

10 Peak capacity factor refers to cleared RPM MW in peak periods (peak hours during January, February, June, July, and August).

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through March 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	1,104.9	485	2.85%
All Wind	2,491.1	615	3.62%

Figure 3-7 Average hourly real-time generation of wind units in PJM, January through March 2011 (See 2010 SOM, Figure 3-13)

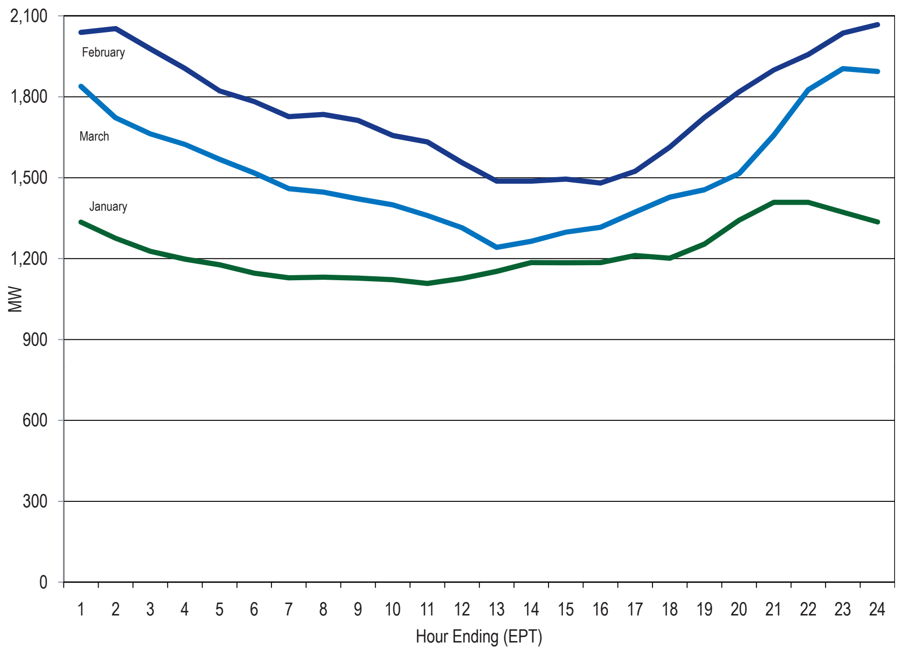


Table 3-36 Capacity factor of wind units in PJM by month, Calendar years 2010 to March 31, 2011[11] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%	909,690.8	29.1%
February	612,044.4	28.6%	1,181,192.0	40.5%
March	727,819.1	29.5%	1,130,037.9	35.0%
April	881,317.4	35.5%		
May	670,571.5	26.2%		
June	472,775.6	18.6%		
July	380,114.8	14.4%		
August	330,818.7	12.1%		
September	705,289.0	24.0%		
October	1,006,233.1	32.5%		
November	1,088,610.5	35.5%		
December	1,118,789.3	35.3%		
Annual	8,812,807.2	27.4%	3,220,920.7	34.5%

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): January through March 2011 (See 2010 SOM, Table 3-56)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.5%				32.5%
	Average Wind Generation	1,407.3				1,407.3
	Average Load	86,939.1				86,939.1
Off-Peak	Capacity Factor	36.2%				36.2%
	Average Wind Generation	1,568.1				1,568.1
	Average Load	75,243.8				75,243.8

11 Capacity factor shown in Table 3-36 is based on all hours in January through March, 2011.

Figure 3-8 Average hourly day-ahead generation of wind units in PJM, January through March 2011 (See 2010 SOM, Figure 3-14)

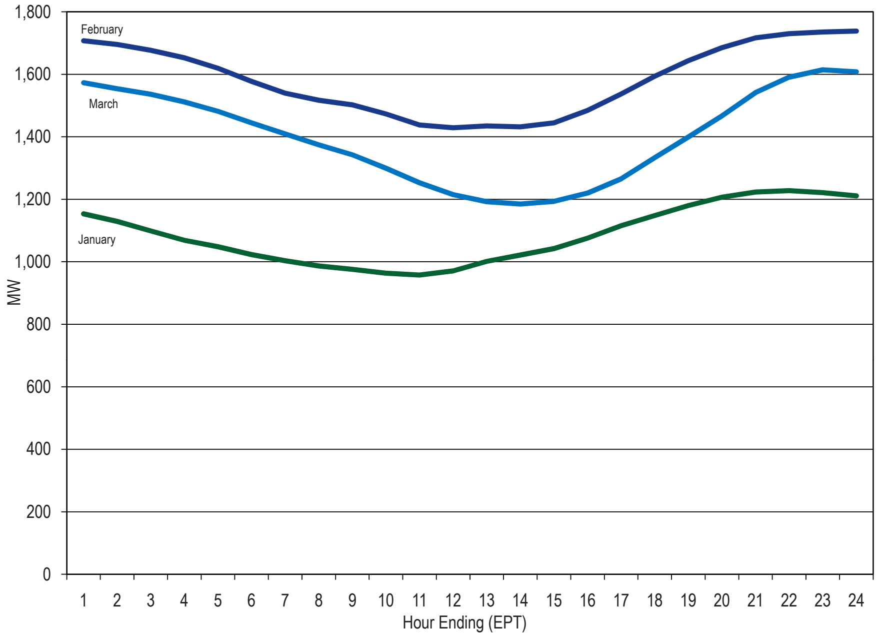
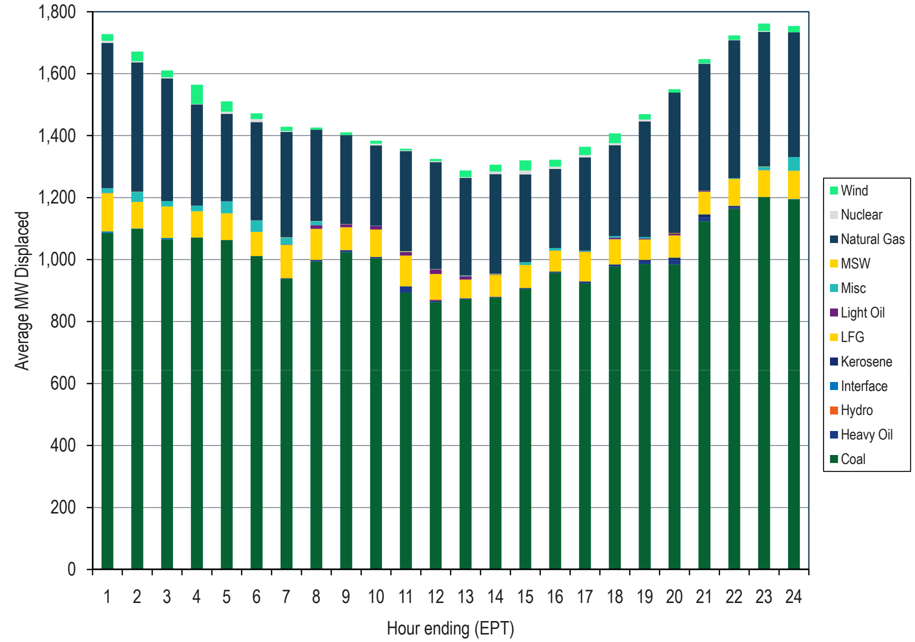


Figure 3-9 Marginal fuel at time of wind generation in PJM, January through March 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-10 Spot average emission price comparison: Calendar year 2010 to March 31, 2011 (See 2010 SOM, Figure 3-16)

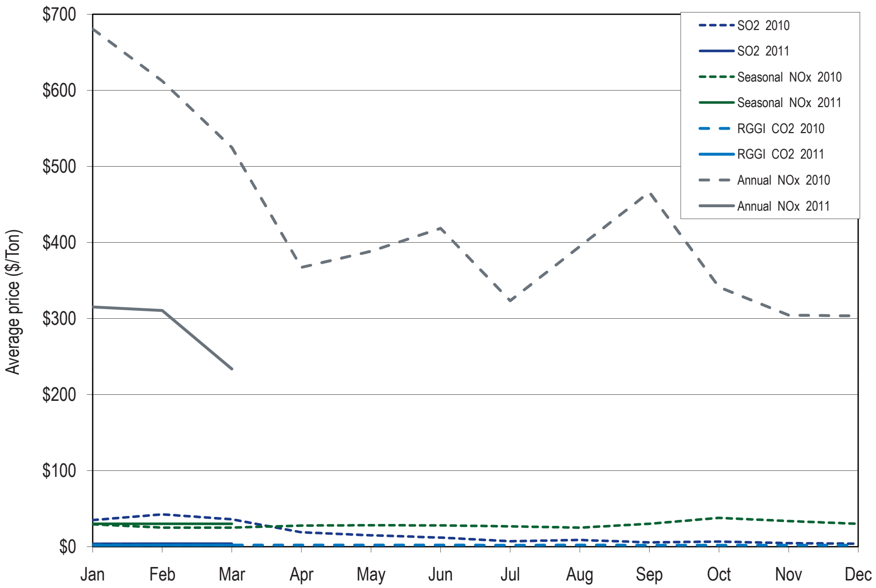


Table 3-38 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[12]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813

Emission Controlled Capacity in the PJM Region

Table 3-39 SO_2 emission controls (FGD) by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-58)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	48,996.7	27,224.0	76,220.7	64.3%
Combined Cycle	0.0	23,598.4	23,598.4	0.0%
Combustion Turbine	0.0	29,463.2	29,463.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	0.0	10,837.0	10,837.0	0.0%
Total	48,996.7	91,465.0	140,461.7	34.9%

Table 3-40 NO_x emission controls by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-59)

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	74,072.9	2,147.8	76,220.7	97.2%
Combined Cycle	23,448.4	150.0	23,598.4	99.4%
Combustion Turbine	24,041.5	5,421.7	29,463.2	81.6%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	127,370.9	13,090.8	140,461.7	90.7%

Table 3-41 Particulate emission controls by unit type (MW), as of March 31, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	74,621.7	1,599.0	76,220.7	97.9%
Combined Cycle	0.0	23,598.4	23,598.4	0.0%
Combustion Turbine	0.0	29,463.2	29,463.2	0.0%
Diesel	0.0	342.4	342.4	0.0%
Non-Coal Steam	3,047.0	7,790.0	10,837.0	28.1%
Total	77,668.7	62,793.0	140,461.7	55.3%

12 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed April 1, 2011).

Renewable Portfolio Standards

Table 3-42 Renewable standards of PJM jurisdictions to 2021[13,14] (See 2010 SOM, Table 3-61)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana	No Standard										
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

Table 3-43 Solar renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-62)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

13 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
14 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 3-44 Additional renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-63)

Jurisdiction		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste		0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)		170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

Table 3-45 Renewable alternative compliance payments in PJM jurisdictions: 2010 (See 2010 SOM, Table 3-64)

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 3-46 Renewable generation by jurisdiction and renewable resource type (GWh): January through March 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Battery	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	13.8	27.6
Indiana	0.0	0.0	0.0	11.0	0.0	0.0	0.0	831.6	842.5	842.5
Illinois	0.0	37.9	0.0	0.0	0.0	2.4	0.0	1,378.2	1,416.1	1,418.5
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	21.3	0.0	565.0	0.0	138.0	0.0	91.3	677.6	815.6
Michigan	0.0	7.9	0.0	14.8	0.0	0.0	0.0	0.0	22.7	22.7
New Jersey	0.0	69.5	132.4	7.4	6.0	339.3	0.0	3.3	86.3	558.0
North Carolina	0.0	0.0	0.0	92.2	0.0	0.0	0.0	0.0	92.2	92.2
Ohio	0.0	9.7	0.0	24.8	0.2	0.0	0.0	0.0	34.7	34.7
Pennsylvania	0.1	214.9	503.4	677.7	0.8	496.0	2,656.5	590.0	1,483.3	5,139.3
Tennessee	0.0	0.0	0.0	0.0	0.0	84.7	0.0	0.0	0.0	84.7
Virginia	0.0	45.6	1,016.7	180.3	0.0	301.9	0.0	0.0	225.9	1,544.4
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	0.0	298.5	0.0	0.0	277.2	326.6	625.1	902.4
Total	0.1	420.6	1,652.5	1,871.7	7.0	1,362.4	2,933.7	3,220.9	5,520.2	11,468.9

Table 3-47 PJM renewable capacity by jurisdiction (MW), on March 31, 2011 (See 2010 SOM, Table 3-66)

Jurisdiction	Battery	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	0.0	8.1	1,827.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,848.1
Illinois	0.0	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	60.0	24.9	129.0	69.0	0.0	1,162.0	0.0	109.0	0.0	120.0	1,673.9
Michigan	0.0	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	0.0	74.9	0.0	0.0	400.0	5.0	58.4	191.1	0.0	7.5	736.9
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	0.0	3,132.7	4.5	0.0	18.0	0.0	116.2	1.1	0.0	0.0	0.0	3,272.5
Pennsylvania	1.0	35.0	199.4	2,240.3	0.0	2,575.0	664.9	3.0	280.0	1,418.9	790.0	8,207.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	0.0	109.1	80.0	17.0	3,588.0	426.1	0.0	231.0	0.0	0.0	4,451.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	318.0	0.0	0.0	0.0	0.0	257.6	0.0	0.0	130.0	430.5	1,136.1
PJM Total	1.0	3,545.7	493.8	4,276.3	117.0	6,563.0	2,968.9	62.5	976.1	1,548.9	4,531.1	25,084.3

Table 3-48 Renewable capacity by jurisdiction, non-PJM units registered in GATS[15,16] (MW), on March 31, 2011 (See 2010 SOM, Table 3-67)

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	9.1	0.0	0.1	9.2
Illinois	0.0	8.7	97.8	0.0	0.0	0.0	10.5	0.0	302.5	419.5
Indiana	0.0	0.0	26.4	0.0	679.1	0.0	0.2	0.0	0.0	705.7
Kentucky	0.0	2.0	16.0	0.0	0.0	0.0	0.2	88.0	0.0	106.2
Maryland	0.0	0.0	5.0	0.0	0.0	0.0	14.8	10.0	0.0	29.8
Michigan	0.0	0.0	37.0	0.0	0.0	0.0	0.1	0.0	0.0	37.1
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	36.5	0.0	0.0	23.3	234.6	0.0	0.2	294.5
New York	0.0	179.9	0.0	0.0	0.0	0.0	0.4	0.0	0.0	180.3
North Carolina	0.0	225.0	5.3	0.0	0.0	0.0	2.0	0.0	0.0	232.3
Ohio	60.0	1.0	42.4	52.6	45.0	0.0	19.9	109.3	9.7	340.0
Pennsylvania	0.0	0.2	5.4	4.8	85.5	0.3	56.5	0.0	3.2	155.9
Tennessee	0.0	12.5	14.8	0.0	0.0	0.0	3.2	318.1	0.0	348.7
Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	0.0	1.5
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.2
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	60.0	429.4	286.7	57.4	809.6	23.6	353.3	525.4	461.8	3,007.2

15 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
16 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed April 01, 2011).

Operating Reserve[17]

Credit and Charge Results

Overall Results

Table 3-49 Monthly operating reserve charges: Calendar years 2010 and 2011 (See SOM 2010, Table 3-72)

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,472,496	$50,803,869	$12,373,099	$110,095	$47,752,503	$60,235,697
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,337,304	$35,416,794
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$24,219,783	$31,123,534
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889				
May	$5,127,307	$131,600	$39,144,404	$44,403,311				
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415				
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778				
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817				
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949				
Oct	$7,719,744	$1,543	$30,433,986	$38,155,273				
Nov	$6,556,715	$29,674	$20,020,310	$26,606,698				
Dec	$12,951,879	$59,954	$83,021,125	$96,032,958				
Total	$30,543,731	$187,554	$79,642,313	$110,373,599	$28,151,021	$315,414	$98,309,589	$126,776,024
Share of Annual Charges	27.7%	0.2%	72.2%	100.0%	22.2%	0.2%	77.5%	100.0%

17 See the *2010 State of the Market Report for PJM* Volume II, Section 3, "Energy Market, Part 2", Table 3-68 *Operating reserve credit and charges* and Table 3-69 *Operating reserve deviations* for details regarding operating reserve structure.

Table 3-50 Regional balancing charges allocation: January through March 2011[18] (See SOM 2010, Table 3-73)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$16,943,025 21.1%	$740,353 0.9%	$17,683,378 22.0%	$30,441,252 37.8%	$10,466,880 13.0%	$10,493,852 13.0%	$51,401,983 63.9%	$69,085,361 85.8%
East	$1,314,882 1.6%	$52,439 0.1%	$1,367,321 1.7%	$2,007,896 2.5%	$681,169 0.8%	$591,083 0.7%	$3,280,149 4.1%	$4,647,469 5.8%
West	$4,573,669 5.7%	$230,503 0.3%	$4,804,172 6.0%	$1,033,628 1.3%	$471,498 0.6%	$436,866 0.5%	$1,941,992 2.4%	$6,746,164 8.4%
Total	$22,831,577 28.4%	$1,023,294 1.3%	$23,854,871 29.6%	$33,482,776 41.6%	$11,619,547 14.4%	$11,521,801 14.3%	$56,624,124 70.4%	$80,478,995 100%

Deviations

Allocation

Table 3-51 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011 (See SOM 2010, Table 3-74)

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,795,075	3,263,461	3,190,976	16,249,511
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,715,163	12,721,102
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,172	2,781,147	12,758,678
Apr	7,006,983	4,668,407	2,132,045	13,807,435				
May	9,004,034	4,228,004	2,416,103	15,648,141				
Jun	10,936,989	3,964,478	3,174,230	18,075,697				
Jul	10,928,408	3,847,011	3,412,498	18,187,917				
Aug	9,747,045	3,417,328	3,188,437	16,352,810				
Sep	9,480,237	3,587,356	2,524,213	15,591,806				
Oct	7,170,712	2,913,554	2,368,303	12,452,569				
Nov	7,606,971	2,860,054	2,485,153	12,952,178				
Dec	10,069,627	4,027,236	3,513,489	17,610,352				
Total	107,168,077	49,691,893	32,634,038	189,494,008	24,501,987	8,540,017	8,687,286	41,729,290
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	58.7%	20.5%	20.8%	100.0%

18 The total charges shown in Table 3-50 do not equal the total balancing charges shown in Table 3-49 because the totals in Table 3-49 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-50 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Table 3-52 Regional charges determinants (MWh): January through March 2011 (See SOM 2010, Table 3-75)

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	174,918,790	7,695,621	182,614,411	24,501,987	8,540,017	8,687,286	41,729,290	224,343,702
East	94,176,944	3,799,175	97,976,119	14,838,976	4,635,609	4,307,451	23,782,036	121,758,155
West	80,741,846	3,896,446	84,638,292	9,612,552	3,865,133	4,379,835	17,857,520	102,495,812

Table 3-53 Monthly impacts on netting deviations: January through March 2011 (See SOM 2010, Table 3-76)

Month	Demand Deviations (MWh) Old Rules	Demand Deviations (MWh) New Rules	Difference	Supply Deviations (MWh) Old Rules	Supply Deviations (MWh) New Rules	Difference	Generator Deviations (MWh) Old Rules	Generator Deviations (MWh) New Rules	Difference
Jan	8,956,331	9,795,075	838,743	3,137,527	3,263,461	125,934	3,198,301	3,191,499	(6,802)
Feb	6,694,980	7,196,554	501,574	2,738,472	2,809,384	70,912	2,729,986	2,715,190	(14,796)
Mar	7,007,409	7,510,358	502,950	2,386,345	2,467,172	80,827	2,790,461	2,783,720	(6,741)
Total	22,658,720	24,501,987	1,843,267	8,262,344	8,540,017	277,673	8,718,748	8,690,408	(28,339)

Table 3-54 Summary of impact on netting deviations: January through March 2011 (See SOM 2010, Table 3-77)

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	22,658,720	8,262,344	8,718,748	39,639,811
New Rules (Netting)	24,501,987	8,540,017	8,690,408	41,732,412
Difference	1,843,267	277,673	(28,339)	2,092,601

Balancing Operating Reserve Charge Rate

Figure 3-11 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): January through March 2011 (See SOM 2010, Figure 3-20)

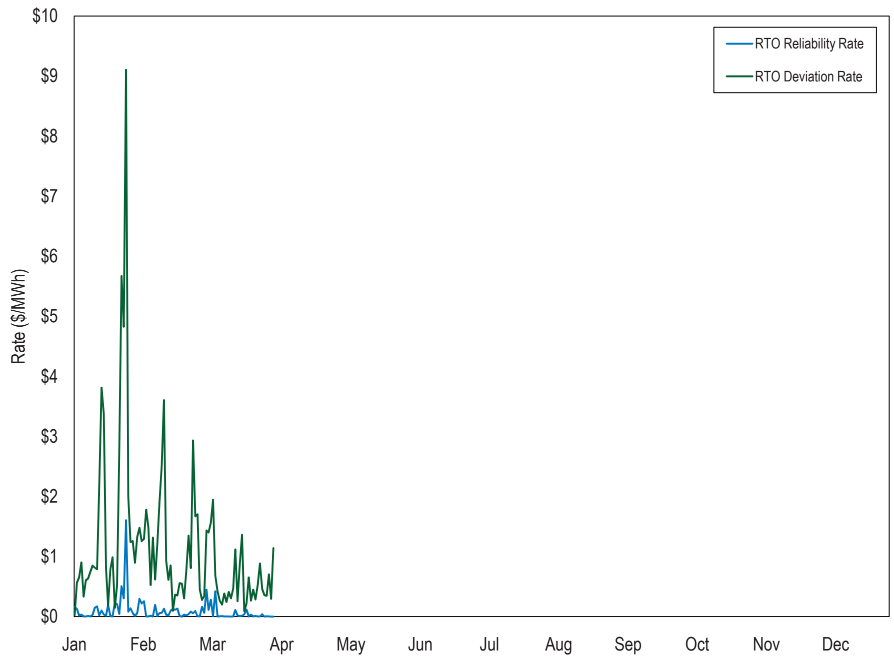


Figure 3-12 Daily regional reliability and deviation rates ($/MWh): January through March 2011 (See SOM 2010, Figure 3-21)

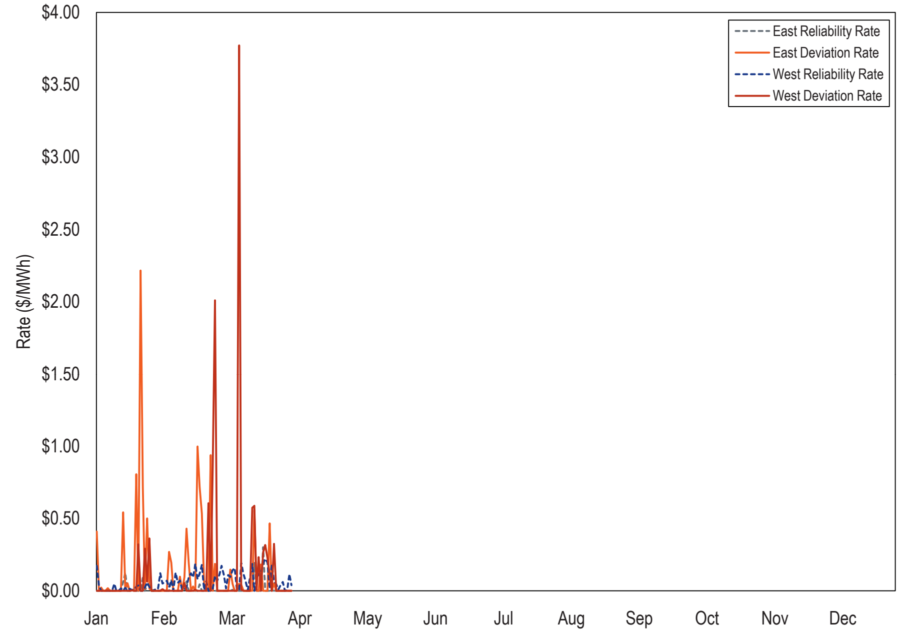


Table 3-55 Regional balancing operating reserve rates ($/MWh): January through March 2011 (See SOM 2010, Table 3-78)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.092	1.141
East	0.000	0.129
West	0.060	0.122

Operating Reserve Credits by Category

Figure 3-13 Operating reserve credits: January through March 2011 (See SOM 2010, Figure 3-22)

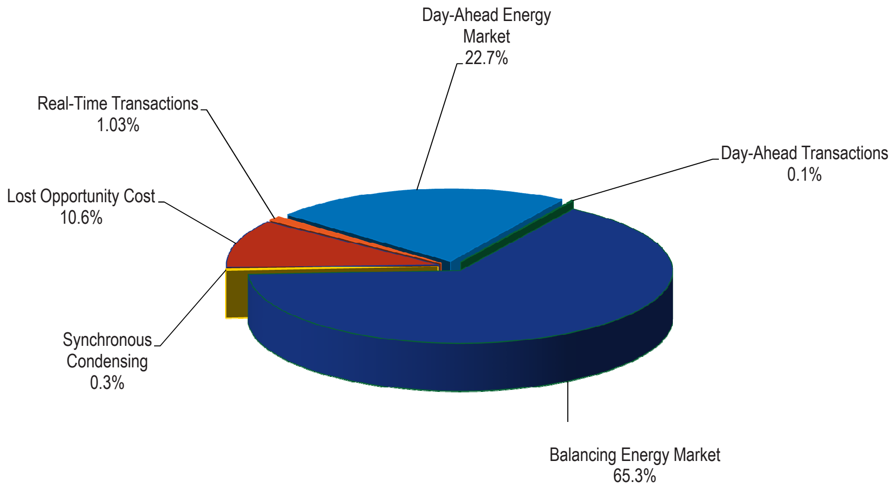


Table 3-56 Credits by month (By operating reserve market): Calendar year 2011[19] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$42,106,060	$473,317	$2,887,804	$57,950,375
Feb	$8,844,162	$96,041	$139,287	$22,787,740	$378,056	$3,171,508	$35,416,794
Mar	$6,830,696	$7,024	$66,032	$15,720,534	$421,862	$7,085,630	$30,131,777
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$28,027,469	$123,553	$315,414	$80,614,333	$1,273,235	$13,144,943	$123,498,946
Share of Credits	22.7%	0.1%	0.3%	65.3%	1.0%	10.6%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-57 Credits by unit types (By operating reserve market): January through March 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	32.7%	0.0%	66.3%	0.9%	$54,660,271
Combustion Turbine	0.8%	0.9%	79.1%	19.2%	$34,123,235
Diesel	0.0%	0.0%	77.2%	22.8%	$75,907
Hydro	0.0%	0.0%	100.0%	0.0%	$731,094
Landfill	0.0%	0.0%	0.0%	100.0%	$5,299,228
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	36.6%	0.0%	60.6%	2.9%	$26,976,468
Wind Farm	0.0%	0.0%	100.0%	0.0%	$204,398

19 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills.

Table 3-58 Credits by operating reserve market (By unit type): January through March 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	63.8%	0.0%	45.0%	3.9%
Combustion Turbine	1.0%	100.0%	33.5%	49.8%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.9%	0.0%
Landfill	0.0%	0.0%	0.0%	40.3%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	35.2%	0.0%	20.3%	5.9%
Wind Farm	0.0%	0.0%	0.3%	0.0%
Total	$28,027,469	$315,414	$80,584,348	$13,143,370

Economic and Noneconomic Generation

Table 3-59 Economic vs. noneconomic hours: January through March 2011 (See SOM 2010, Table 3-82)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	6,302	60.4%	4,135	39.6%	10,437
Combustion Turbine	1,095	23.3%	3,602	76.7%	4,697
Diesel	31	16.4%	158	83.6%	189
Steam	13,702	84.7%	2,467	15.3%	16,169

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-60 Regional balancing operating reserve credits: January through March 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$17,683,378	$51,401,983	$69,085,361
East	$1,367,321	$3,280,149	$4,647,469
West	$4,769,142	$1,941,992	$6,711,134
Total	$23,819,840	$56,624,124	$80,443,964

Table 3-61 Total deviations: January through March 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	24,501,987	8,540,017	8,687,286	41,729,290

Table 3-62 Charge allocation under old operating reserve construct: January through March 2011 (See SOM 2010, Table 3-88)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,501,987	8,540,017	8,687,286	41,729,290
Balancing Rate ($/MWh)	1.928	1.928	1.928	1.928
Charges ($)	$47,233,896	$16,463,084	$16,746,984	$80,443,964

Table 3-63 Actual regional credits, charges, rates and charge allocation (MWh): January through March 2011 (See SOM 2010, Table 3-89)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$17,683,378	182,614,411	0.097	$17,683,378	$51,401,983	41,729,290	1.232	$51,401,983	$69,085,361
East	$1,367,321	97,976,119	0.014	$1,367,321	$3,280,149	23,782,036	0.138	$3,280,149	$4,647,469
West	$4,769,142	83,735,322	0.057	$4,769,142	$1,941,992	17,720,520	0.110	$1,941,992	$6,711,134
Total	$23,819,840	182,614,411	NA	$23,819,840	$56,624,124	41,729,290	NA	$56,624,124	$80,443,964

Table 3-64 Difference in total operating reserve charges between old rules and new rules: January through March 2011 (See SOM 2010, Table 3-90)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$47,233,896	$16,463,084	$16,746,984	$80,443,964
Charges (Current)	$22,797,761	$1,022,080	$23,819,840	$33,482,776	$11,619,547	$11,521,801	$56,624,124
Difference	$22,797,761	$1,022,080	$23,819,840	($13,751,120)	($4,843,538)	($5,225,183)	($23,819,840)

Impact on Decrement Bids and Incremental Offers

Table 3-65 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through March, 2010 and 2011 (See SOM 2010, Table 3-91)

	2010				2011			
Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047	6,054,214	8,284,810	1,548,295	3,162,842
Feb	8,323,844	11,828,781	2,004,162	2,234,045	5,732,202	7,440,032	1,376,811	2,271,323
Mar	8,032,429	11,159,303	2,150,898	2,594,826	5,372,006	7,753,370	1,152,806	2,548,787
Apr	7,568,471	9,989,951	2,214,314	2,066,270				
May	8,306,597	11,573,314	2,250,271	3,437,786				
Jun	8,304,139	12,735,819	2,223,204	4,058,044				
Jul	8,389,094	12,813,573	1,840,017	3,503,722				
Aug	7,862,123	11,648,289	1,465,333	2,676,901				
Sep	8,188,967	11,532,284	2,103,152	3,105,498				
Oct	7,777,616	10,423,935	1,564,871	2,163,717				
Nov	8,027,852	11,041,950	1,408,786	2,467,942				
Dec	9,416,187	12,320,592	1,920,956	3,451,929				
Total	98,488,750	140,097,307	23,609,817	35,212,727	17,158,422	23,478,211	4,077,912	7,982,952

Table 3-66 Comparison of balancing operating reserve charges to virtual bids: January through March, 2010 and 2011 (See SOM 2010, Table 3-92)

	2010			2011		
Month	Charges Under Old Rules	Charges Under Current Rules	Difference	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)	$10,130,258	$13,855,712	($3,725,454)
Feb	$5,319,874	$3,936,420	($1,383,454)	$5,758,334	$7,474,212	($1,715,879)
Mar	$4,797,076	$3,468,829	($1,328,248)	$4,945,666	$6,666,882	($1,721,216)
Apr	$6,480,725	$5,301,308	($1,179,417)			
May	$13,658,944	$10,158,307	($3,500,637)			
Jun	$18,021,960	$10,673,612	($7,348,348)			
Jul	$17,068,724	$14,327,987	($2,740,737)			
Aug	$9,394,993	$7,575,980	($1,819,013)			
Sep	$13,065,704	$10,820,010	($2,245,694)			
Oct	$9,019,721	$6,456,368	($2,563,353)			
Nov	$5,817,780	$3,925,450	($1,892,330)			
Dec	$17,570,579	$19,884,462	$2,313,884			
Total	$132,741,464	$106,719,600	($26,021,864)	$20,834,257	$27,996,806	($7,162,549)

Table 3-67 Summary of impact on virtual bids under balancing operating reserve allocation: January through March, 2010 and 2011 (See SOM 2010, Table 3-93)

	Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Current Rules ($/MWh)	Balancing Rate Under Old Rules ($/MWh)	Charges Under Current Rules	Charges Under Old Rules	Differerence
2010	RTO	6,618,912	8,280,918	14,899,830	0.942	1.383	$15,650,032	$22,371,028	($6,720,997)
	East	4,481,203	4,848,963	9,330,165	0.118	0.000	$1,097,057	$0	$1,097,057
	West	2,113,208	3,385,979	5,499,187	0.119	0.000	$603,725	$0	$603,725
2011	RTO	4,077,912	7,982,952	12,060,863	1.515	2.194	$19,384,060	$27,996,806	($8,612,746)
	East	2,201,838	3,753,224	5,955,062	0.135	0.000	$802,288	$0	$802,288
	West	1,836,798	4,179,269	6,016,067	0.113	0.000	$647,909	$0	$647,909

Segmented Make Whole Payments

Table 3-68 Impact of segmented make whole payments: January through March 2011 (See SOM 2010, Table 3-94)

	2010			2011		
Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
Jan	$32,982,105	$33,924,489	$942,385	$40,721,858	$41,949,204	$1,227,346
Feb	$17,321,317	$17,609,133	$287,815	$21,621,511	$22,774,422	$1,152,911
Mar	$13,458,120	$13,672,172	$214,052	$14,872,573	$15,695,526	$822,954
Apr	$16,441,644	$17,036,058	$594,414			
May	$21,854,306	$23,455,721	$1,601,415			
Jun	$36,297,521	$38,885,349	$2,587,828			
Jul	$32,251,623	$37,053,630	$4,802,007			
Aug	$21,867,024	$24,335,171	$2,468,147			
Sep	$24,293,196	$25,686,790	$1,393,593			
Oct	$21,839,101	$22,478,455	$639,354			
Nov	$15,795,391	$16,238,383	$442,991			
Dec	$49,180,164	$51,293,810	$2,113,646			
Total	$303,581,512	$321,669,160	$18,087,648	$77,215,942	$80,419,153	$3,203,211

Table 3-69 Impact of segmented make whole payments (By unit type): January through March 2011 (See SOM 2010, Table 3-95)

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	242	$4,685	$8,177	$3,492	$1,133,762	$1,978,773	$845,011
Medium Frame Combustion Turbine (30 - 65 MW)	434	$2,255	$2,802	$547	$978,722	$1,215,955	$237,233
Large Frame Combustion Turbine (135 - 180 MW)	24	$17,622	$24,943	$7,321	$422,925	$598,631	$175,705
Petroleum/Gas Steam (Post-1985)	13	$5,227	$11,677	$6,450	$67,946	$151,798	$83,852
Sub-Critical Coal	98	$51	$618	$567	$5,023	$60,591	$55,569
Medium-Large Frame Combustion Turbine (65 - 125 MW)	60	$3,960	$4,745	$786	$237,571	$284,716	$47,145
Small Frame Combustion Turbine (0 - 29 MW)	34	$3,177	$3,361	$183	$108,025	$114,264	$6,239
Diesel	1	$0	$1,210	$1,210	$0	$1,210	$1,210

Table 3-70 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through March 2011 (See SOM 2010, Table 3-96)

Unit Type	Share of Increase
Combined-Cycle	14.2%
Steam	4.8%
Combustion Turbines	73.8%
Diesel	7.1%

Unit Operating Parameters[20]

Table 3-71 Units receiving credits from a parameter limited schedule: January through March 2011 (See SOM 2010, Table 3-98)

Unit Type	Number of Units	Observations
Combined-Cycle	1	1
Large Frame Combustion Turbine (135 - 180 MW)	2	3
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	33
Petroleum/Gas Steam (Pre-1985)	1	2
Sub-Critical Coal	13	76

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-72 Unit operating reserve credits for units (By zone): January through March 2011 (See SOM 2010, Table 3-100)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$81,262	$0	$1,027,344	$430,881	$1,539,486	1.3%
AEP	$518,737	$0	$7,863,677	$269,853	$8,652,267	7.2%
AP	$503,257	$0	$2,686,329	$968,560	$4,158,146	3.5%
BGE	$3,162,984	$0	$1,914,686	$11,195	$5,088,865	4.2%
ComEd	$130,850	$0	$879,129	$549,700	$1,559,678	1.3%
DAY	$1,568	$0	$196,770	$5,025	$203,363	0.2%
Dominion	$818,887	$0	$12,941,842	$8,647,410	$22,408,140	18.6%
DPL	$409,631	$0	$2,926,557	$281,793	$3,617,981	3.0%
DLCO	$145,077	$0	$851,816	$0	$996,893	0.8%
JCPL	$1,227,517	$0	$3,439,615	$50,489	$4,717,621	3.9%
Met-Ed	$66,745	$0	$408,577	$313	$475,635	0.4%
PECO	$350,877	$4,692	$1,339,968	$217,677	$1,913,213	1.6%
PENELEC	$0	$0	$522,328	$245,087	$767,415	0.6%
Pepco	$1,175,318	$0	$5,029,368	$599,501	$6,804,187	5.7%
PPL	$49,265	$0	$3,322,132	$488,089	$3,859,486	3.2%
PSEG	$19,153,341	$310,354	$33,908,994	$222,480	$53,595,169	44.5%
External	$0	$0	$0	$0	$0	0.0%
Total	$27,795,315	$315,046	$79,259,131	$12,988,053	$120,357,545	100.0%

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 3, "Energy Market, Part 2," Table 3-97 *Unit Parameter Limited Schedule Matrix* for details regarding default unit operating parameters.

Table 3-73 Top 10 units and organizations receiving total operating reserve credits: January through March 2011 (See SOM 2010, Table 3-101)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$18,619,098	18.1%	18.1%	$49,165,106	47.9%	47.9%
2	$15,086,428	14.7%	32.8%	$8,141,922	7.9%	55.8%
3	$5,101,609	5.0%	37.8%	$6,291,698	6.1%	61.9%
4	$3,172,914	3.1%	40.9%	$5,679,306	5.5%	67.5%
5	$2,300,662	2.2%	43.1%	$4,714,947	4.6%	72.1%
6	$1,842,375	1.8%	44.9%	$3,933,095	3.8%	75.9%
7	$1,668,308	1.6%	46.5%	$3,172,914	3.1%	79.0%
8	$1,452,456	1.4%	48.0%	$3,020,195	2.9%	81.9%
9	$1,225,256	1.2%	49.2%	$2,263,372	2.2%	84.1%
10	$1,198,615	1.2%	50.3%	$1,381,434	1.3%	85.5%

Table 3-74 Top 10 units and organizations receiving day-ahead generator credits: January through March 2011 (See SOM 2010, Table 3-102)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$9,030,534	29.7%	29.7%	$19,975,372	65.7%	65.7%
2	$4,481,756	14.7%	44.4%	$1,840,078	6.1%	71.7%
3	$3,300,358	10.9%	55.3%	$1,125,078	3.7%	75.4%
4	$1,840,078	6.1%	61.3%	$1,088,419	3.6%	79.0%
5	$1,593,833	5.2%	66.6%	$970,016	3.2%	82.2%
6	$1,086,840	3.6%	70.1%	$872,676	2.9%	85.1%
7	$963,905	3.2%	73.3%	$751,554	2.5%	87.5%
8	$585,511	1.9%	75.2%	$654,220	2.2%	89.7%
9	$348,635	1.1%	76.4%	$573,047	1.9%	91.6%
10	$323,106	1.1%	77.4%	$522,597	1.7%	93.3%

Table 3-75 Top 10 units and organizations receiving synchronous condensing credits: January through March 2011 (See SOM 2010, Table 3-103)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$20,686	11.0%	11.0%	$156,309	83.3%	83.3%
2	$14,462	7.7%	18.7%	$13,768	7.3%	90.7%
3	$12,753	6.8%	25.5%	$8,905	4.7%	95.4%
4	$11,874	6.3%	31.9%	$6,477	3.5%	98.9%
5	$10,763	5.7%	37.6%	$2,095	1.1%	100.0%
6	$10,748	5.7%	43.3%			
7	$8,118	4.3%	47.7%			
8	$7,821	4.2%	51.8%			
9	$7,264	3.9%	55.7%			
10	$7,182	3.8%	59.5%			

Table 3-76 Top 10 units and organizations receiving balancing generator credits: January through March 2011 (See SOM 2010, Table 3-104)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$14,137,342	21.8%	21.8%	$28,999,449	44.7%	44.7%
2	$6,055,299	9.3%	31.2%	$7,136,836	11.0%	55.7%
3	$1,801,251	2.8%	33.9%	$5,328,108	8.2%	64.0%
4	$1,598,443	2.5%	36.4%	$5,217,078	8.0%	72.0%
5	$1,441,118	2.2%	38.6%	$2,827,369	4.4%	76.4%
6	$1,332,836	2.1%	40.7%	$1,982,601	3.1%	79.4%
7	$1,198,615	1.8%	42.5%	$1,845,025	2.8%	82.3%
8	$1,181,333	1.8%	44.3%	$1,332,836	2.1%	84.3%
9	$930,953	1.4%	45.8%	$1,171,163	1.8%	86.1%
10	$904,293	1.4%	47.2%	$1,158,356	1.8%	87.9%

Table 3-77 Top 10 units and organizations receiving lost opportunity cost credits: January through March 2011 (See SOM 2010, Table 3-105)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$886,383	12.2%	12.2%	$4,713,550	65.1%	65.1%
2	$682,772	9.4%	21.7%	$762,534	10.5%	75.6%
3	$635,812	8.8%	30.4%	$391,996	5.4%	81.0%
4	$591,740	8.2%	38.6%	$390,543	5.4%	86.4%
5	$544,001	7.5%	46.1%	$208,377	2.9%	89.3%
6	$522,921	7.2%	53.3%	$132,410	1.8%	91.1%
7	$427,283	5.9%	59.2%	$70,289	1.0%	92.1%
8	$335,251	4.6%	63.9%	$65,973	0.9%	93.0%
9	$241,343	3.3%	67.2%	$61,475	0.8%	93.8%
10	$216,586	3.0%	70.2%	$57,968	0.8%	94.6%

Recommendations

Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-78 is based on calculating notification and startup times independently, then adding together. Table 3-79 is based on adding notification and startup times together first, then calculating distribution. All data are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-78 Cold notification and cold startup hours (By percentile): Since November 2007 (New table)

	Cold Notification Time			Cold Startup Time			CS + CN		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	4	8.5	18	12.5	14	18	16.5	22.5	36
Petroleum/Gas Steam (Post-1985)	1	1	2	6	12	14	7	13	16
Combined-Cycle	2	5	7	5	6.2	8	7	11.2	15
Sub-Critical Coal	2	2	4	15	16	20	17	18	24
Super-Critical Coal	2	2	8	19	20	22	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	0.25	1	2	0.5	0.5	0.8	0.75	1.5	2.8
Medium Frame Combustion Turbine (30 - 65 MW)	0.2	0.3	1.4	0.3	0.5	0.5	0.5	0.8	1.9
Medium-Large Frame Combustion Turbine (65 - 135 MW)	1	2	2	0.5	0.7	1	1.5	2.7	3
Large Frame Combustion Turbine (135 - 180 MW)	2	5	6	0.5	0.7	1	2.5	5.7	7

Table 3-79 Time-To-Start hours (By percentile): Since November 2007 (New table)

	All Months			Peak Months			Off-Peak Months		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	18	20	32	18	20	30	17	19	32
Petroleum/Gas Steam (Post-1985)	9	13	14	9	13	14	9	13	14
Combined-Cycle	9	11	14	8.5	10	13.5	9	11	14
Sub-Critical Coal	16.5	18	22	16.5	18	22.5	16	18	22
Super-Critical Coal	21	22	30	21	22	30	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	1	1.5	2.2	1	1.5	2.2	1	1.5	2.2
Medium Frame Combustion Turbine (30 - 65 MW)	0.5	0.8	1.7	0.5	0.7	1.7	0.5	1	2
Medium-Large Frame Combustion Turbine (65 - 135 MW)	2	2	3.3	2	2	3.3	2	2.3	3.4
Large Frame Combustion Turbine (135 - 180 MW)	3	5	6.6	2.5	4.3	6.6	4	5	6.8

Parameter Limited Schedules

Currently, parameter limited schedules are only enforced for cost-based schedules, except for emergencies, permitting the use of price-based schedule parameters as a possible method to exercise market power. For example, a unit may extend a minimum down time to avoid being turned off when not economic, which will increase operating reserve credits to the unit and operating reserve charges paid by other participants. The MMU recommends the enforcement of parameter limit for both cost-based and market-based schedules.

SECTION 4 - INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Highlights

- 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.

- 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.

- 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.

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

- 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.

- 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.

- 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.

Summary Recommendations

- 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.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2011, PJM was a net exporter of energy in the Real-Time Energy Market in February and March, and a net importer of energy in January. During the first three months of 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -267 GWh compared to -281 GWh for the first three months of 2010.[1] Gross monthly import volumes averaged 3,775 GWh compared to 3,837 GWh for the first three months of 2010 while gross monthly exports averaged 4,042 GWh compared to 4,118 GWh for the first three months of 2010.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. During the first three months of 2010, PJM was a net exporter of energy in the Day-Ahead

1 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

Energy Market in all months. In the Day-Ahead Energy Market, monthly net interchange averaged 1,271 GWh compared to -260 GWh for the first three months of 2010. Gross monthly import volumes averaged 9,387 GWh compared to 5,182 GWh for the first three months of 2010 while gross monthly exports averaged 8,116 GWh compared to 5,442 GWh for the first three months of 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market during the first three months of 2011 was the significant increase in up-to congestion transactions. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 1,078 bids per day (with an average cleared volume of 423,077 MWh per day) during the first three months of 2011, compared to an average of 337 bids per day (with an average cleared volume of 178,843 MWh per day) during the first three months of 2010. (See Figure 4-20).

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** During the first three months of 2011, gross imports in the Day-Ahead Energy Market were 249 percent of gross imports in the Real-Time Energy Market compared to 210 percent for the calendar year 2010, gross exports in the Day-Ahead Energy Market were 201 percent of gross exports in the Real-Time Energy Market compared to 183 percent for the calendar year 2010, and net interchange in the Day-Ahead Energy Market was 476 percent of net interchange in the Real-Time Energy Market compared to -802.0 GWh in the Real-Time Energy Market and 3,813.9 GWh in the Day-Ahead Energy Market.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, during the first three months of 2011, there were net exports at twelve of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 63 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 29 percent, PJM/MidAmerican Energy Company (MEC) with 18 percent and PJM/Neptune (NEPT) with 16 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 51 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net imports, with two importing interfaces accounting for 71 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 54 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 17 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, during the first three months of 2011, there were net exports at ten of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 24 percent, PJM/NEPT with 21 percent and PJM/FirstEnergy Corp. (FE) with 15 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 36 percent of the total net PJM exports in the Day-Ahead Energy Market. Ten PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 87 percent of the total net imports: PJM/OVEC with 35 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 32 percent and PJM/Michigan Electric Coordinated System (MECS) with 20 percent.[3]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first three months of 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.34 while the Midwest ISO LMP at the border was $35.76, a difference of $1.42, while the average hourly flow during the first three months of 2011 was -1,712 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 38 percent of hours during the first three months of 2011. During the first three months of 2011, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $15.93. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was -$7.93. While the average hourly LMP difference at the PJM/MISO border was only $1.42, the average of the absolute values of the hourly differences was $11.05.

- **PJM and New York ISO Interface Prices.** During the first three months of 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface

2 In the Real-Time Market, two PJM interface had a net interchange of zero (PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/City Water Light & Power (CWLP)).

3 In the Day-Ahead Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. During the first three months of 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the PJM/NYISO border was $46.77 while the NYISO LMP at the border was $47.35, a difference of $0.58, while the average hourly flow was -787 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is consistent with the fact that the average PJM price was lower than the average NYISO price.) The direction of flows was consistent with price differentials in only 53 percent of the hours during the first three months of 2011. During the first three months of 2011, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $15.25. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was -$15.50. While the average hourly LMP difference at the PJM/NYISO border was only $0.58, the average of the absolute value of the hourly difference was $15.35.

- **Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line from PJM (Sayreville, New Jersey), to NYISO (Nassau County on Long Island) with a capacity of 660 MW. The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. During the first three months of 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the Neptune Interface was $52.51 while the NYISO LMP at the Neptune Bus was $60.11, a difference of $7.60, while the average hourly flow in 2010 was -533 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 65 percent of the hours during the first three months of 2011. While the average hourly LMP difference at the PJM/Neptune border was only $7.60, the average of the absolute value of the hourly difference was $23.15.

- **Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission connection, with a capacity of 300 MW, providing a direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[4] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16. The revision seeks to add Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.[5] The requested effective date for this revision, which allows for the bidirectional flow across the Linden VFT, is June 1, 2011. During the first three months of 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. During the first three months of 2011, the PJM average hourly LMP at the Linden Interface was $51.43 while the NYISO LMP at the Linden Bus was $57.96, a difference of $6.53, while the average hourly flow was -193 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours during the first three months of 2011. While the average hourly LMP difference at the PJM/Linden border was $6.53, the average of the absolute value of the hourly difference was $20.54.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[6] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued during the first three months of 2011.

4 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.
5 See Docket No. ER11-3250-000 (March 31, 2011).
6 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed May 5, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

- **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first three months of 2011. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[7] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect during the first three months of 2011.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[8] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect during the first three months of 2011. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP).

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[9] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first three months of 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[10] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces.

  Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

  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).

7 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

8 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).

9 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed May 4, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

10 111 FERC ¶ 61,228 (2005).

Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2010, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-4,863 GWh during the first three months of 2011 and -15,106 GWh for the calendar year 2010). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (872 GWh during the first three months of 2011 and 4,015 GWh for the calendar year 2010). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant during the first three months of 2011. PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) are in the west. The largest differences in the west were at the TVA Interface. The net scheduled power flow at the TVA Interface was 840 GWh and the actual flow was 1,712 GWh, a difference of 872 GWh. PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK are in the east. The largest differences in the east were at the CPLE Interface. The net scheduled power flow at the CPLE Interface was 7 GWh and the actual flow was 2,650 GWh, a difference of 2,643 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first three months of 2011, PJM issued 13 TLRs of level 3a or higher. Of the 13 TLRs issued, 8 events were TLR level 3a, and the remaining 5 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 13 TLRs during the first three months of 2011, compared to 13 during the first three months of 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level.

- **Marginal Loss Surplus Allocation.** On May 15, 2010, in an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[11] PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus.

  As a result, on September 17, 2010, the marginal loss surplus allocation methodology was modified to mitigate the incentive of submitting noneconomic transactions to benefit from loss surplus allocations.

- **Up-To Congestion.** The May 15, 2010, modification to the marginal loss surplus allocation provided an allocation to up-to congestion transactions. In June and July of 2010, there was a significant increase in the total up-to congestion bids (Figure 4-19). This increase in activity was the result of the changes to the allocation methodology that provided an inappropriate incentive to submit noneconomic up-to congestion transactions to obtain a portion of the loss surplus.

  As part of the September 2010, marginal loss surplus allocation modification, the up-to congestion product was modified to eliminate the requirement for up-to congestion transactions to obtain transmission service. In order to minimize the effects of eliminating the transmission requirement for up-to congestion transactions, PJM created a new product on the OASIS, called "Up-to Congestion". Market participants are still required to access the PJM OASIS and obtain an "up-to congestion" reservation. However, the product is not limited by ATC, nor is there a charge associated with the product. The sole purpose of this product is to allow market participants to specify specific sources and sinks for which up-to congestion transactions will be evaluated in the Day-Ahead Market.

11 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

Prior to the May 15, 2010, modification to the marginal surplus allocation, the average daily volume of up-to congestion was 376 bids per day (March 1, 2009 through May 14, 2010). The average daily volume of up-to congestion transactions increased to 762 bids per day for the period between the initial May 15, 2010, modification and the additional modification to the marginal loss surplus allocation methodology made on September 17, 2010. The average daily volume of up-to congestion bids further increased to 1,338 bids per day following the additional modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids, which was implemented as part of the September 17, 2010 marginal loss surplus allocation methodology changes (September 17, 2010 through March 31, 2011). (See Figure 4-20.)

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

  The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service; and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

- **Elimination of Sources and Sinks.** The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

- **Spot Import.** In 2009, PJM and the MMU jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it. To address the issue, PJM implemented new timing requirements that retracted spot import reservations if they were associated with a NERC Tag within 30 minutes of making the reservation. Although this resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service to flow energy. As a result, the MMU and PJM recommended that PJM revert to unlimited ATC for non-firm willing to pay congestion service. The PJM Stakeholders agreed with the recommendation, and requested that PJM determine what would be needed to implement the change.

- **Real-Time Dispatchable Transactions.** Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. For example, an import dispatchable transaction would specify the minimum price the market participant wishes to receive when selling into the PJM market. If the interface pricing point for the transaction is expected to be greater than the price specified by the market participant, the transaction would be loaded for the next hour. For an export dispatchable transaction, the market participant specifies the maximum price they are willing to buy from at the interface pricing point. Once the transaction is submitted and the NERC Tag is implemented, PJM should curtail the tag to 0 MW pending the real-time economic evaluation during the operating day for which the transaction is submitted. PJM dispatchers evaluate dispatchable transactions 30 minutes prior to the hour. If they believe the LMP at the interface pricing point will be economic they will load the transaction for the next hour. Once loaded, the transaction will flow for the entire hour. Dispatchable transactions receive the hourly integrated pricing point LMP for the hours when energy flows. For import transactions, if the hourly integrated import pricing point LMP is less than the price specified, the market participant is made whole through balancing operating reserve credits. Exporting dispatchable transactions are not made whole, as Schedule 6 of the PJM Open Access Transmission Tariff does not include export transactions in the calculation for balancing operating reserve credits.

Dispatchable transactions were initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits. During the first three months of 2011, $1.1 million in balancing operating reserve credits were paid due to the uneconomic loading of dispatchable transactions comparted to $92,742 during first three months of 2010.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first three months of 2011, including evolving transaction patterns, economics and issues. During the first three months of 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. A large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 63 percent of the total real-time net exports and two interfaces accounted for 71 percent of the real-time net import volume. Three interfaces accounted for 60 percent of the total day-ahead net exports and three interfaces accounted for 87 percent of the day-ahead net import volume.

During the first three months of 2011, 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 for many hours, 62 percent between PJM and the Midwest ISO and 47 percent between PJM and NYISO. The MMU recommends that PJM work with both Midwest ISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through March 2011 (See 2010 SOM, Figure 4-1)

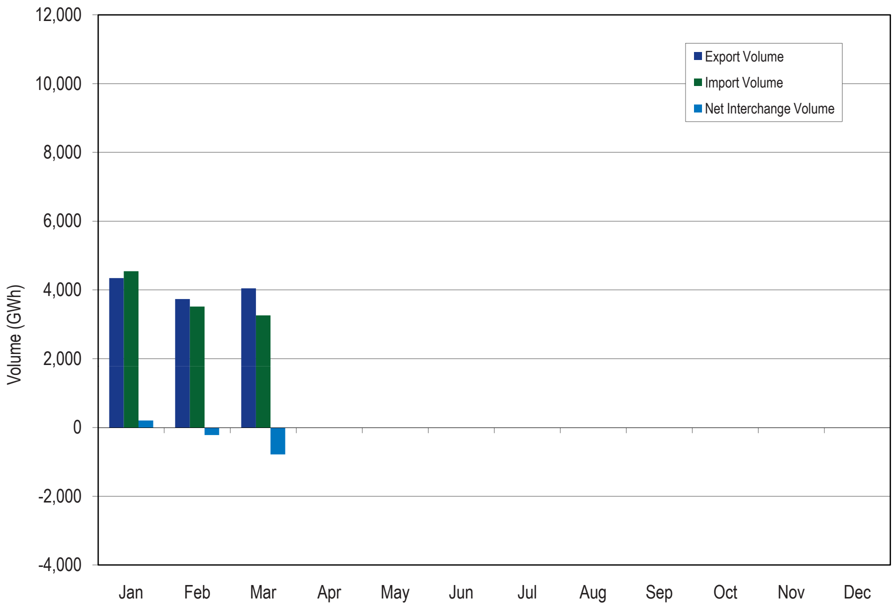


Figure 4-2 PJM day-ahead scheduled imports and exports: January through March 2011 (See 2010 SOM, Figure 4-2)

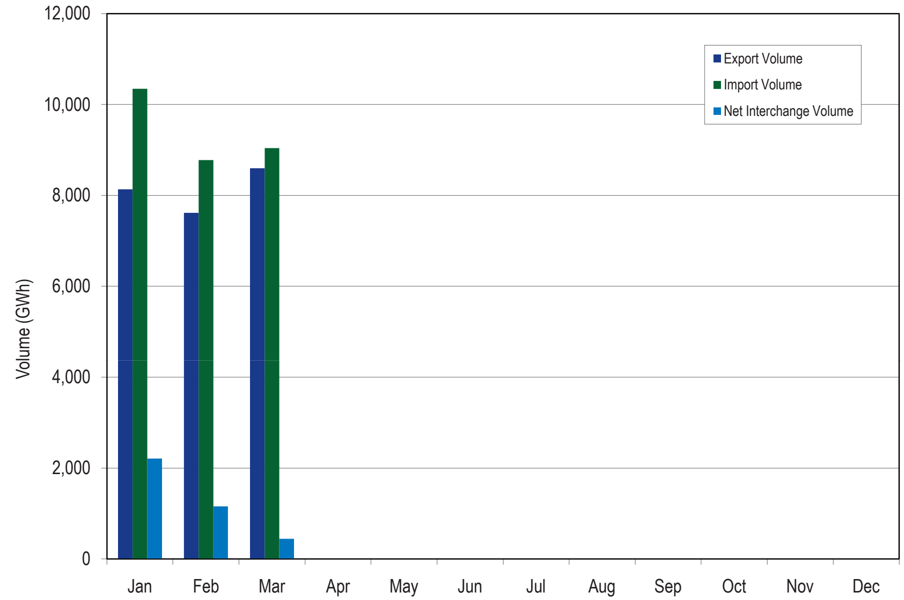
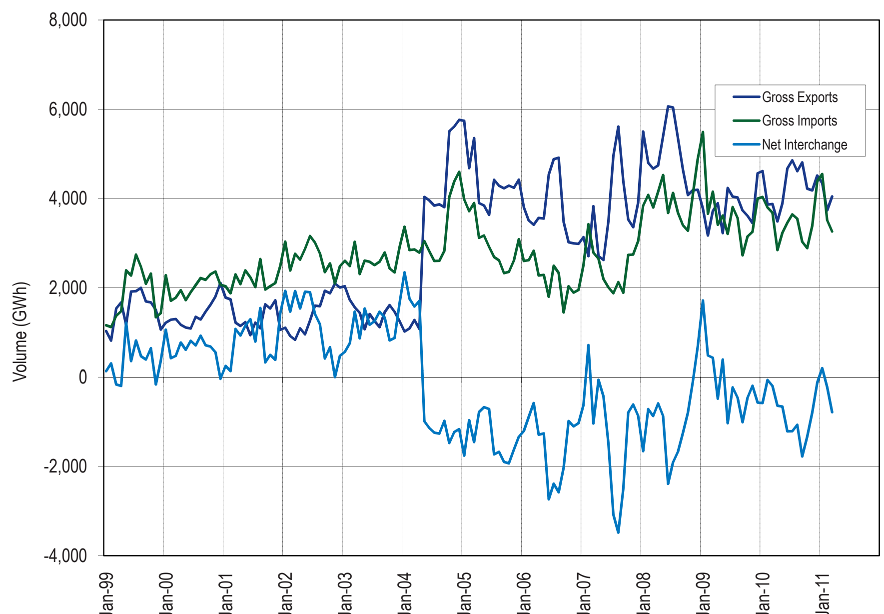


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through March 2011 (See 2010 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-1)

	Jan	Feb	Mar	Total
CPLE	(162.6)	(76.3)	(85.5)	(324.4)
CPLW	0.0	0.0	0.0	0.0
DUK	(25.6)	218.7	(17.1)	176.0
EKPC	(61.4)	(10.1)	5.6	(65.9)
LGEE	392.9	385.9	314.6	1,093.4
MEC	(426.0)	(403.3)	(462.2)	(1,291.5)
MISO	(77.3)	(389.0)	(744.4)	(1,210.7)
ALTE	(116.1)	(128.3)	(76.0)	(320.4)
ALTW	(30.9)	(14.5)	(28.6)	(74.0)
AMIL	(2.9)	45.5	14.3	56.9
CIN	(85.5)	(314.7)	(454.6)	(854.8)
CWLP	0.0	0.0	0.0	0.0
FE	149.9	(43.9)	(159.1)	(53.1)
IPL	21.8	3.5	8.8	34.1
MECS	193.0	190.8	112.6	496.4
NIPS	(114.3)	(51.0)	(69.7)	(235.0)
WEC	(92.3)	(76.4)	(92.1)	(260.8)
NYISO	(1,361.0)	(1,279.3)	(1,032.0)	(3,672.3)
LIND	(159.1)	(148.1)	(117.7)	(424.9)
NEPT	(412.9)	(378.8)	(383.7)	(1,175.4)
NYIS	(789.0)	(752.4)	(530.6)	(2,072.0)
OVEC	1,242.2	1,110.7	1,065.8	3,418.7
TVA	681.6	222.8	170.3	1,074.7
Total	202.8	(219.9)	(784.9)	(802.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-2)

	Jan	Feb	Mar	Total
CPLE	6.4	7.4	4.6	18.4
CPLW	0.0	0.0	0.0	0.0
DUK	271.7	309.8	186.2	767.7
EKPC	31.7	46.5	41.0	119.2
LGEE	393.0	386.3	324.1	1,103.4
MEC	53.2	30.8	19.1	103.1
MISO	1,141.5	833.9	736.6	2,712.0
ALTE	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0
AMIL	23.9	68.0	42.2	134.1
CIN	400.0	270.3	315.2	985.5
CWLP	0.0	0.0	0.0	0.0
FE	436.8	220.5	122.3	779.6
IPL	25.4	4.8	15.3	45.5
MECS	250.9	270.3	241.4	762.6
NIPS	0.0	0.0	0.2	0.2
WEC	4.5	0.0	0.0	4.5
NYISO	681.0	534.7	646.6	1,862.3
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	681.0	534.7	646.6	1,862.3
OVEC	1,242.2	1,110.7	1,091.3	3,444.2
TVA	725.7	255.5	212.0	1,193.2
Total	4,546.4	3,515.6	3,261.5	11,323.5

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-3)

	Jan	Feb	Mar	Total
CPLE	169.0	83.7	90.1	342.8
CPLW	0.0	0.0	0.0	0.0
DUK	297.3	91.1	203.3	591.7
EKPC	93.1	56.6	35.4	185.1
LGEE	0.1	0.4	9.5	10.0
MEC	479.2	434.1	481.3	1,394.6
MISO	1,218.8	1,222.9	1,481.0	3,922.7
ALTE	116.1	128.3	76.0	320.4
ALTW	30.9	14.5	28.6	74.0
AMIL	26.8	22.5	27.9	77.2
CIN	485.5	585.0	769.8	1,840.3
CWLP	0.0	0.0	0.0	0.0
FE	286.9	264.4	281.4	832.7
IPL	3.6	1.3	6.5	11.4
MECS	57.9	79.5	128.8	266.2
NIPS	114.3	51.0	69.9	235.2
WEC	96.8	76.4	92.1	265.3
NYISO	2,042.0	1,814.0	1,678.6	5,534.6
LIND	159.1	148.1	117.7	424.9
NEPT	412.9	378.8	383.7	1,175.4
NYIS	1,470.0	1,287.1	1,177.2	3,934.3
OVEC	0.0	0.0	25.5	25.5
TVA	44.1	32.7	41.7	118.5
Total	4,343.6	3,735.5	4,046.4	12,125.5

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through March 2011 (See 2010 SOM, Table 4-4)

	Jan	Feb	Mar	Total
CPLE	(11.3)	89.8	126.7	205.2
CPLW	17.1	6.4	1.9	25.4
DUK	91.7	115.8	41.0	248.5
EKPC	(27.5)	(18.4)	27.8	(18.1)
LGEE	19.0	1.8	2.0	22.8
MEC	(458.7)	(421.4)	(463.2)	(1,343.3)
MISO	2,144.3	904.6	(182.2)	2,866.7
ALTE	1,996.5	908.2	99.1	3,003.8
ALTW	164.8	(49.7)	(48.1)	67.0
AMIL	34.6	70.2	67.5	172.3
CIN	(125.8)	(90.5)	(175.1)	(391.4)
CWLP	0.0	0.0	0.0	0.0
FE	(189.4)	(339.7)	(317.2)	(846.3)
IPL	(175.6)	(162.6)	(163.9)	(502.1)
MECS	742.4	580.2	567.2	1,889.8
NIPS	(280.6)	(111.0)	(130.3)	(521.9)
WEC	(22.6)	99.5	(81.4)	(4.5)
NYISO	(892.0)	(681.9)	(496.7)	(2,070.6)
LIND	(105.0)	(104.7)	(77.9)	(287.6)
NEPT	(427.9)	(379.7)	(385.0)	(1,192.6)
NYIS	(359.1)	(197.5)	(33.8)	(590.4)
OVEC	1,046.0	1,051.1	1,279.5	3,376.6
TVA	282.8	111.2	106.7	500.7
Total	2,211.4	1,159.0	443.5	3,813.9

Table 4-5 Day-ahead gross import volume by interface (GWh): January through March 2011 (See 2010 SOM, Figure 4-5)

	Jan	Feb	Mar	Total
CPLE	137.6	146.3	197.4	481.3
CPLW	19.5	6.5	8.1	34.1
DUK	150.8	155.5	88.5	394.8
EKPC	5.4	0.0	28.3	33.7
LGEE	21.6	2.1	13.5	37.2
MEC	21.7	19.8	20.1	61.6
MISO	7,393.7	5,782.6	5,316.8	18,493.1
ALTE	4,872.3	3,576.6	3,109.0	11,557.9
ALTW	375.6	52.1	29.0	456.7
AMIL	44.8	71.1	70.7	186.6
CIN	266.2	440.5	360.6	1,067.3
CWLP	0.0	0.0	0.0	0.0
FE	232.7	140.5	141.0	514.2
IPL	17.0	2.9	0.0	19.9
MECS	1,409.4	1,207.9	1,438.1	4,055.4
NIPS	32.0	48.2	27.0	107.2
WEC	143.7	242.8	141.4	527.9
NYISO	910.1	988.6	1,149.1	3,047.8
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	910.1	988.6	1,149.1	3,047.8
OVEC	1,272.8	1,355.2	1,898.8	4,526.8
TVA	412.1	318.7	318.9	1,049.7
Total	10,345.3	8,775.3	9,039.5	28,160.1

Table 4-6 Day-ahead gross export volume by interface (GWh): January through March 2011 (See 2010 SOM, Figure 4-6)

	Jan	Feb	Mar	Total
CPLE	148.9	56.5	70.7	276.1
CPLW	2.4	0.1	6.2	8.7
DUK	59.1	39.7	47.5	146.3
EKPC	32.9	18.4	0.5	51.8
LGEE	2.6	0.3	11.5	14.4
MEC	480.4	441.2	483.3	1,404.9
MISO	5,249.4	4,878.0	5,499.0	15,626.4
ALTE	2,875.8	2,668.4	3,009.9	8,554.1
ALTW	210.8	101.8	77.1	389.7
AMIL	10.2	0.9	3.2	14.3
CIN	392.0	531.0	535.7	1,458.7
CWLP	0.0	0.0	0.0	0.0
FE	422.1	480.2	458.2	1,360.5
IPL	192.6	165.5	163.9	522.0
MECS	667.0	627.7	870.9	2,165.6
NIPS	312.6	159.2	157.3	629.1
WEC	166.3	143.3	222.8	532.4
NYISO	1,802.1	1,670.5	1,645.8	5,118.4
LIND	105.0	104.7	77.9	287.6
NEPT	427.9	379.7	385.0	1,192.6
NYIS	1,269.2	1,186.1	1,182.9	3,638.2
OVEC	226.8	304.1	619.3	1,150.2
TVA	129.3	207.5	212.2	549.0
Total	8,133.9	7,616.3	8,596.0	24,346.2

Interface Pricing

Table 4-7 Active interfaces: January through March 2011 (See 2010 SOM, Figure 4-7)

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
EKPC	Active	Active	Active
FE	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 4-4 PJM's footprint and its external interfaces (See 2010 SOM, Figure 4-4)

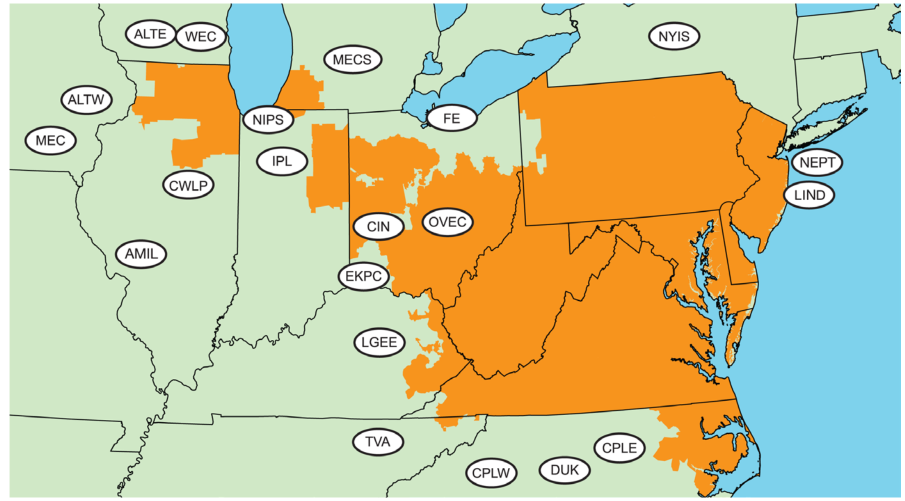


Table 4-8 Active pricing points: 2011 (See 2010 SOM, Table 4-8)

PJM 2011 Pricing Points (January through March)				
CPLEEXP	CPLEIMP	DUKEXP	DUKIMP	LIND
MICHFE	MISO	NCMPAEXP	NCMPAIMP	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO	OVEC
SOUTHEXP	SOUTHIMP			

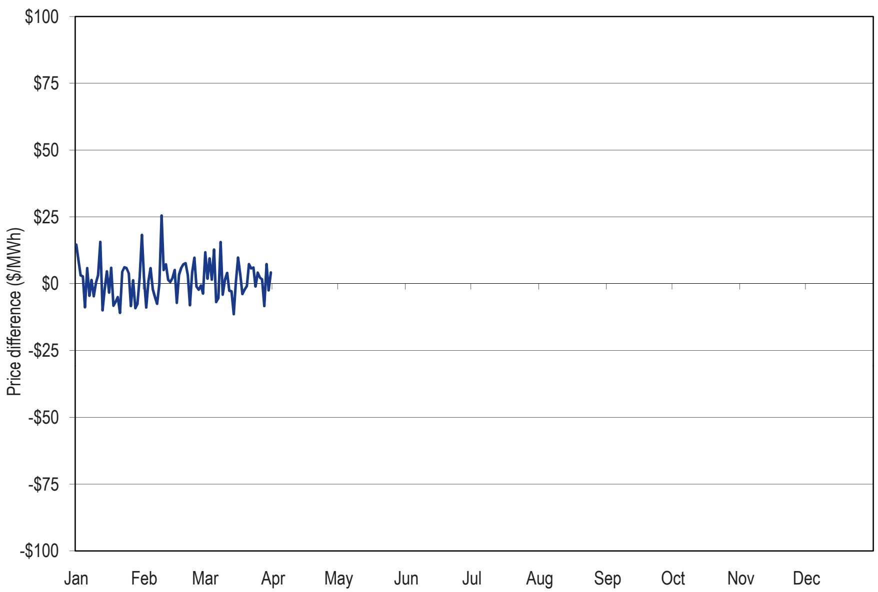
Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and Midwest ISO Interface Prices

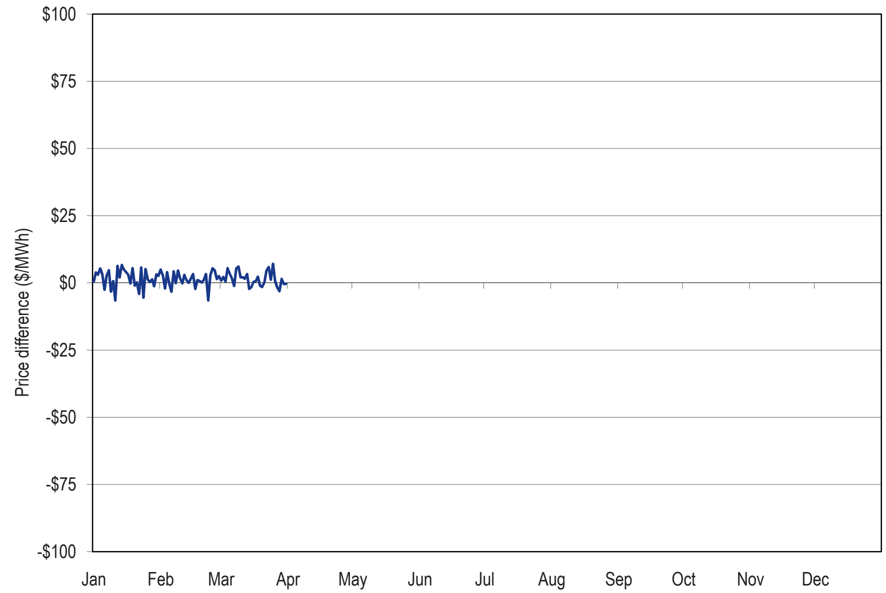
Real-Time Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through March 2011 (See 2010 SOM, Figure 4-5)



Day-Ahead Prices

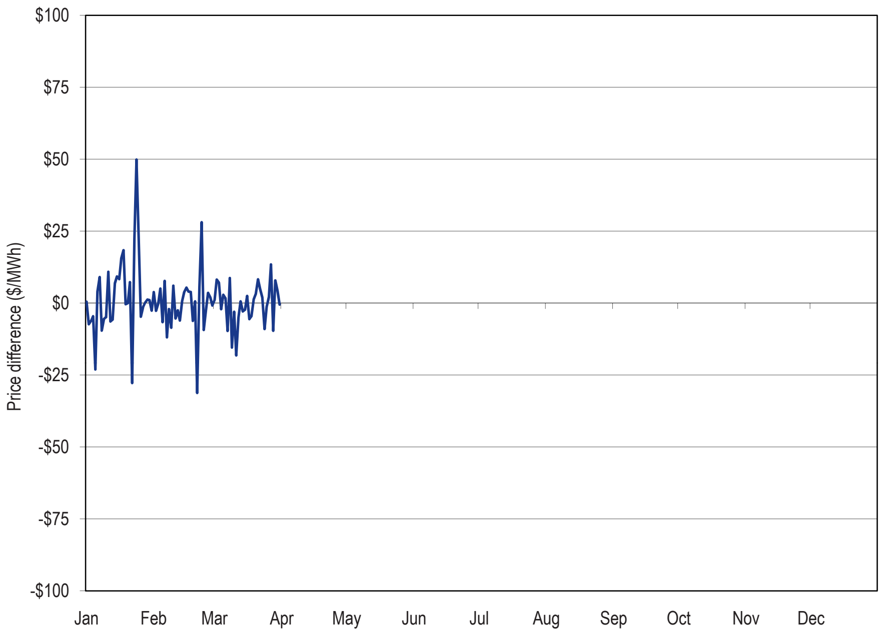
Figure 4-6 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through March 2011 (See 2010 SOM, Figure 4-6)



PJM and NYISO Interface Prices

Real-Time Prices

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2011 (See 2010 SOM, Figure 4-7)



Day-Ahead Prices

Figure 4-8 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2011 (See 2010 SOM, Figure 4-8)

Summary of Interface Prices between PJM and Organized Markets

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: January through March 2011 (See 2010 SOM, Figure 4-9)

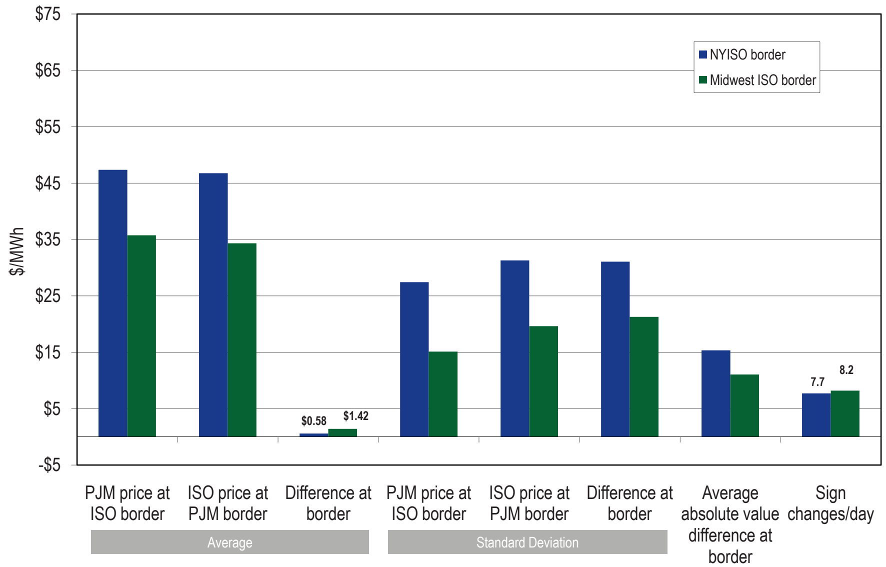
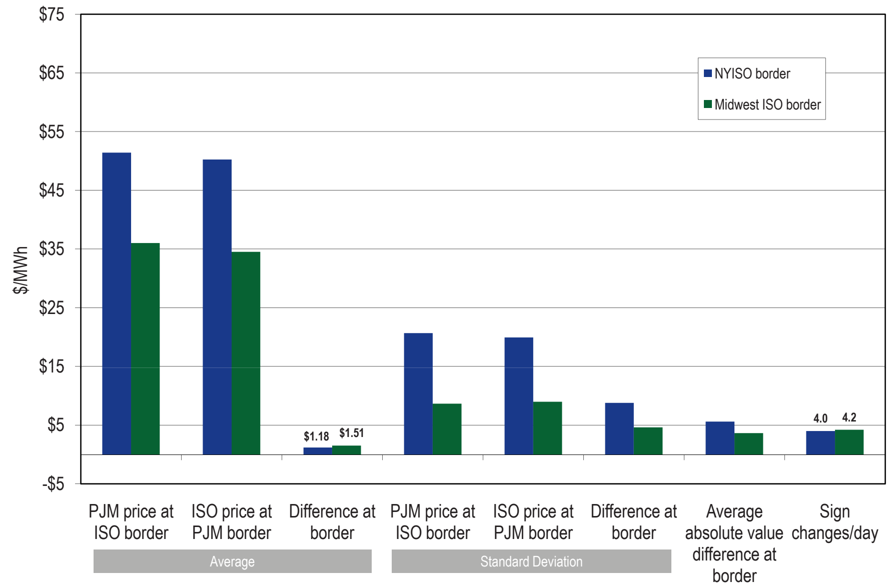
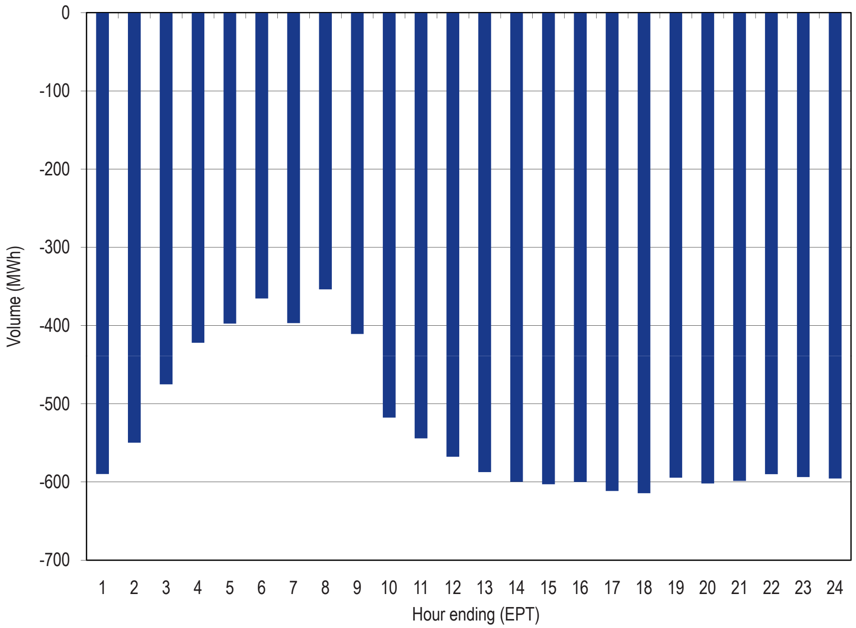


Figure 4-10 PJM, NYISO and Midwest ISO day-ahead border price averages: January through March 2011 (See 2010 SOM, Figure 4-10)



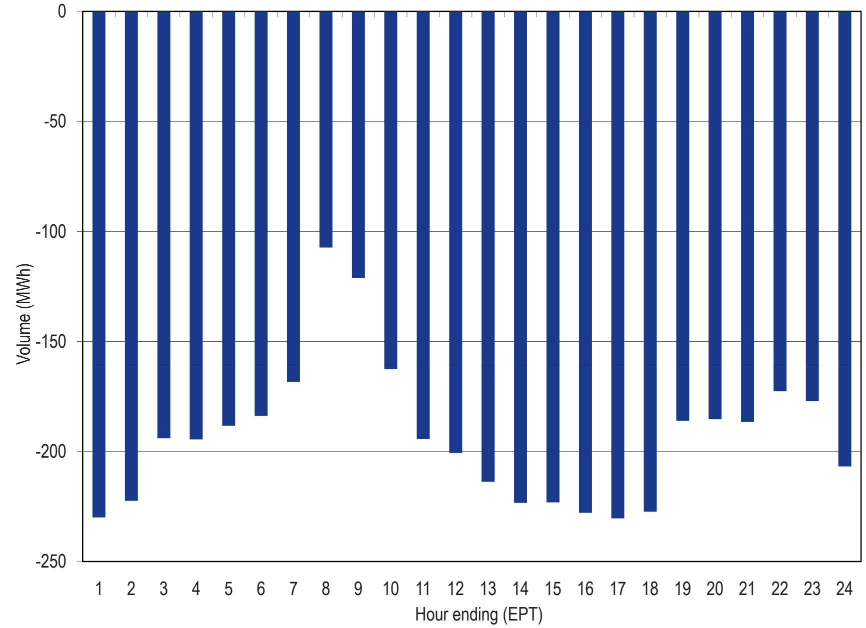
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-11 Neptune hourly average flow: January through March 2011 (See 2010 SOM, Figure 4-11)



Linden Variable Frequency Transformer (VFT) facility

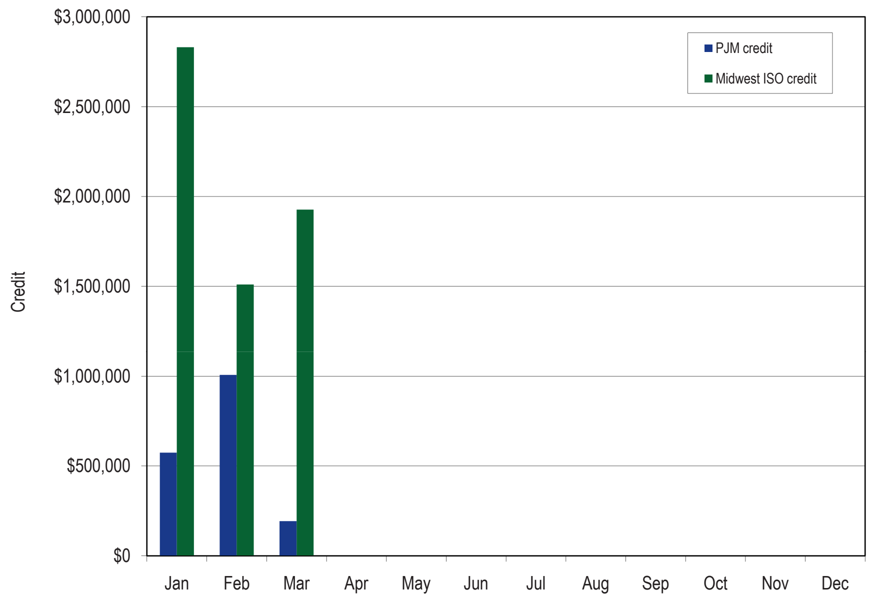
Figure 4-12 Linden hourly average flow: January through March 2011 (See 2010 SOM, Figure 4-12)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

Figure 4-13 Credits for coordinated congestion management: January through March 2011 (See 2010 SOM, Figure 4-13)



Other Agreements/Protocols with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

Table 4-9 Con Edison and PSE&G wheeling settlement data: January through March 2011 (See 2010 SOM, Table 4-9)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	($435,152)	($36)	($435,189)	($6,301,035)	$0	($6,301,035)
Congestion Credit			$1,713			($6,290,717)
Adjustments			$15,127			$1,295
Net Charge			($452,028)			($11,613)

Interchange Transaction Issues

Loop Flows

Table 4-10 Net scheduled and actual PJM interface flows (GWh): January through March 2011 (See 2010 SOM, Table 4-10)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	2,650	7	2,643	37,757%
CPLW	(422)	-	(422)	0%
DUK	(345)	176	(521)	(296%)
EKPC	703	(66)	769	(1,165)%
LGEE	379	1,093	(714)	(65%)
MEC	(763)	(1,289)	526	(41%)
MISO	(3,694)	(572)	(3,122)	546%
ALTE	(1,494)	(320)	(1,174)	367%
ALTW	(554)	(74)	(480)	649%
AMIL	3,183	34	3,149	9,262%
CIN	620	147	473	322%
CWLP	(29)	-	(29)	0%
FE	(1,539)	(352)	(1,187)	337%
IPL	456	(7)	463	(6,614%)
MECS	(4,367)	496	(4,863)	(980%)
NIPS	(1,333)	(235)	(1,098)	467%
WEC	1,363	(261)	1,624	(622%)
NYISO	(3,265)	(3,682)	417	(11%)
LIND	(416)	(416)	-	0%
NEPT	(1,150)	(1,150)	-	0%
NYIS	(1,699)	(2,116)	417	(20%)
OVEC	2,834	3,419	(585)	(17%)
TVA	1,712	840	872	104%
Total	(211)	(74)	(137)	185.1%

Loop Flows at PJM's Southern Interfaces

Figure 4-14 Southwest actual and scheduled flows: January 2006 through March 2011 (See 2010 SOM, Figure 4-14)

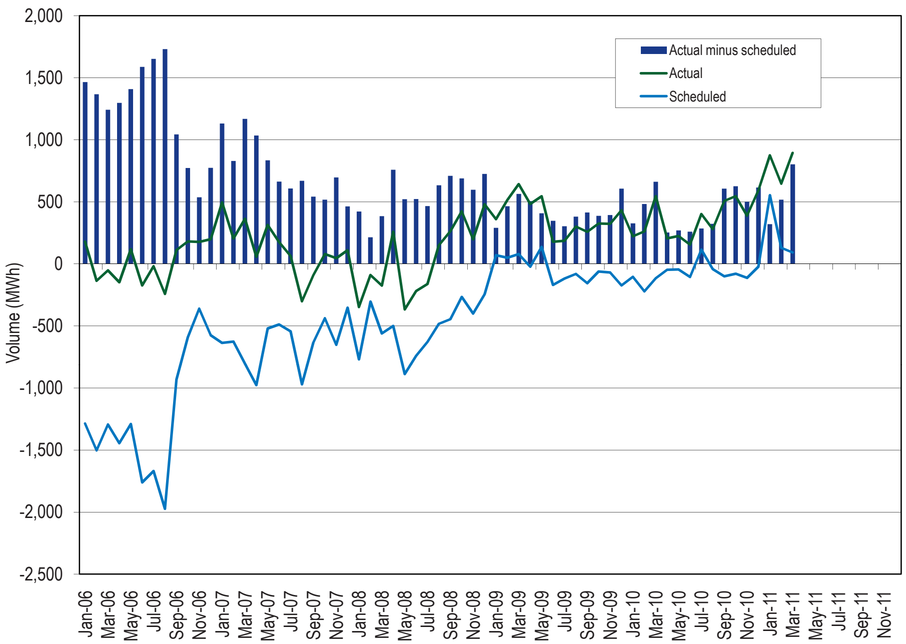
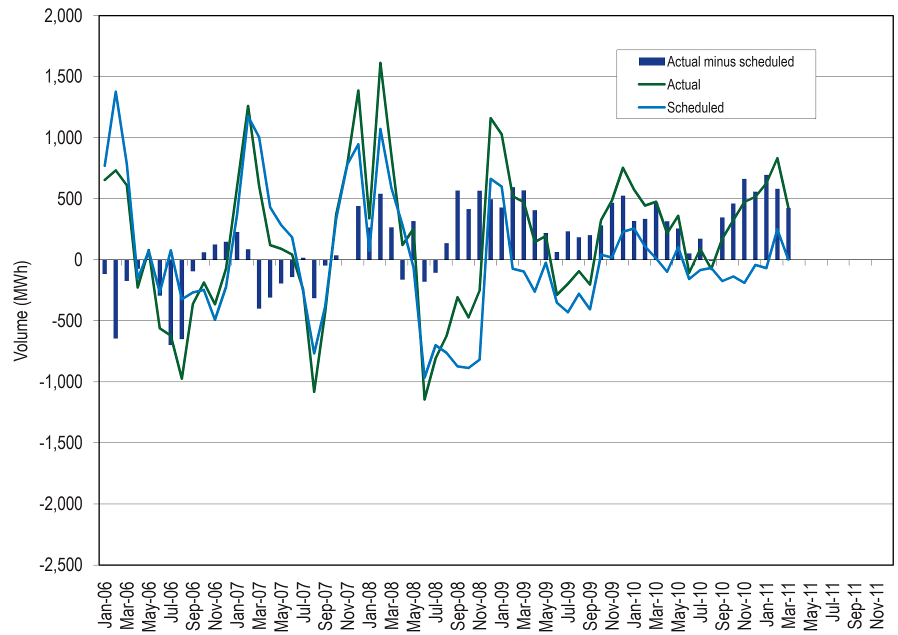


Figure 4-15 Southeast actual and scheduled flows: January 2006 through March 2011 (See 2010 SOM, Figure 4-15)



Dynamic Interface Pricing

Figure 4-16 PJM and Midwest ISO TLR procedures: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-16)

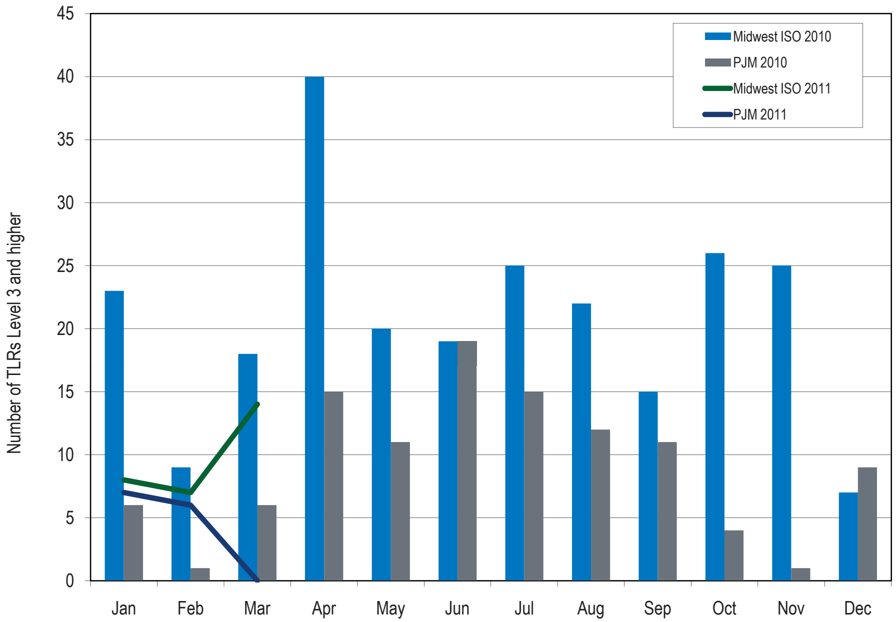


Figure 4-17 Number of different PJM flowgates that experienced TLRs: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-17)

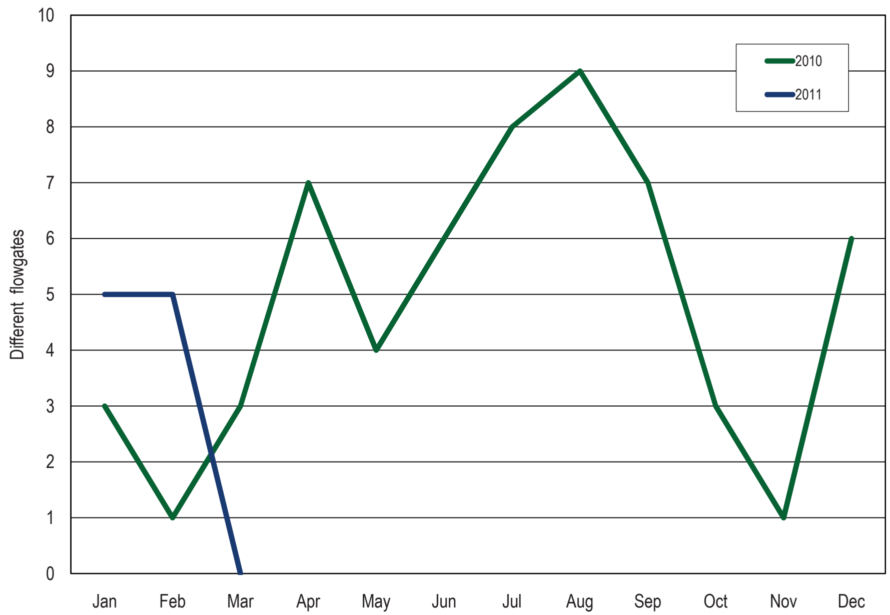


Figure 4-18 Number of PJM TLRs and curtailed volume: January through March 2011 (See 2010 SOM, Figure 4-18)

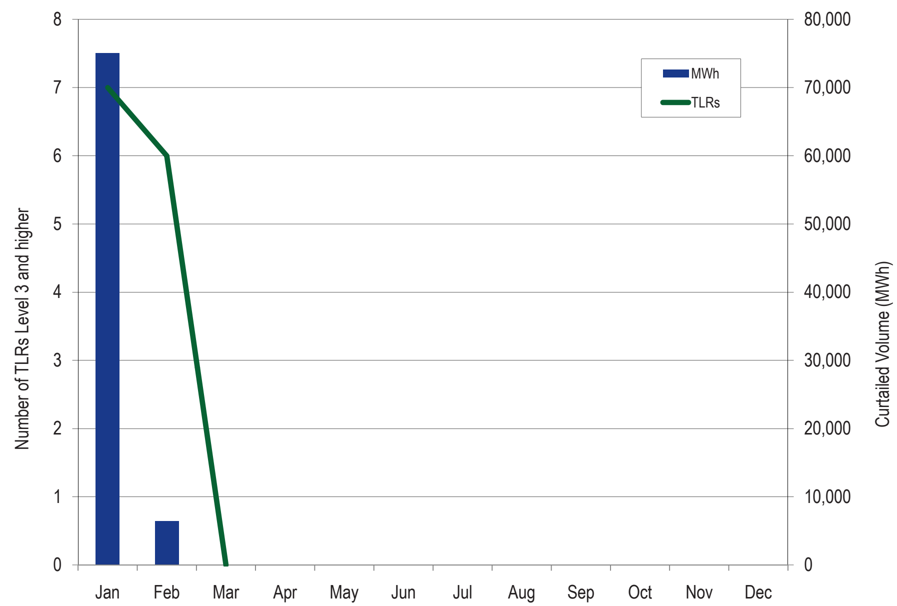


Table 4-11 Number of TLRs by TLR level by reliability coordinator: January through March 2011 (See 2010 SOM, Table 4-11)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2011	ICTE	3	1	49	4	2	0	59
	MISO	19	9	0	1	0	0	29
	NYIS	68	0	0	0	0	0	68
	ONT	11	0	0	0	0	0	11
	PJM	8	5	0	0	0	0	13
	SWPP	63	88	1	7	10	0	169
	TVA	27	46	2	0	8	0	83
Total		199	149	52	12	20	0	432

Up-To Congestion

Figure 4-19 Monthly up-to congestion bids in MWh: January 2006 through March 2011 (See 2010 SOM, Figure 4-19)

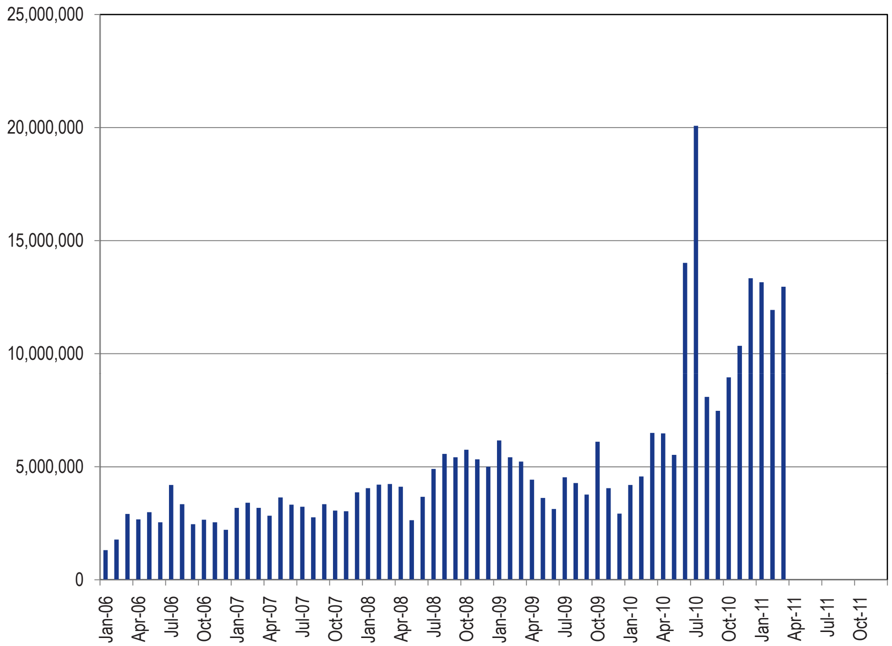


Figure 4-20 Unique up-to congestion bids with approved MWh: March 2009 through March 2011 (New Figure)

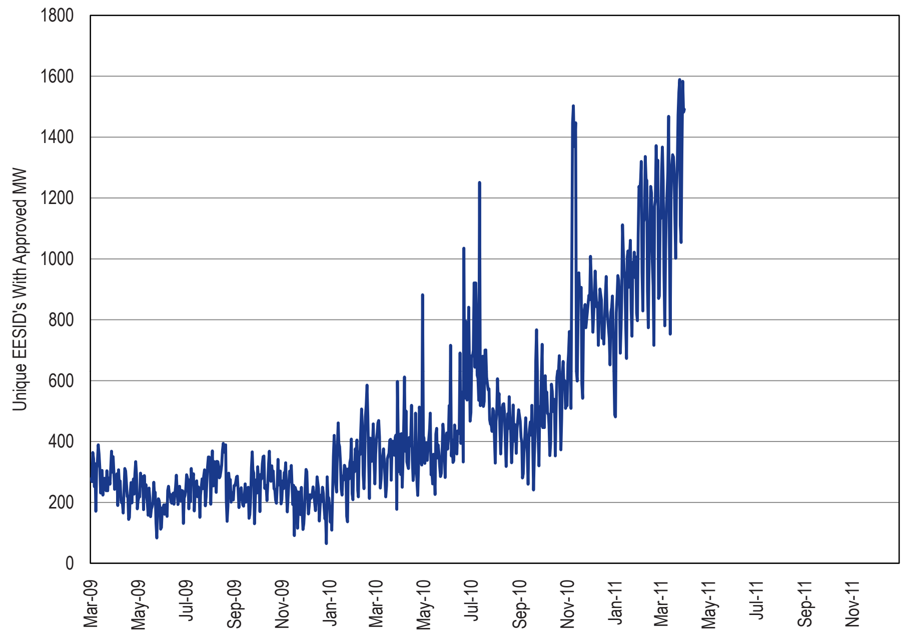


Table 4-12 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through March 2011 (See 2010 SOM, Table 4-12)

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
2010	54,662,719	48,723,549	6,147,957	109,534,225	49.9%	44.5%	5.6%
2011	21,826,485	15,379,380	840,190	38,046,055	57.4%	40.4%	2.2%
TOTAL	146,515,707	168,657,266	11,360,458	326,533,431	44.9%	51.7%	3.5%

Figure 4-21 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction: January through March 2011 (See 2010 SOM, Figure 4-20)

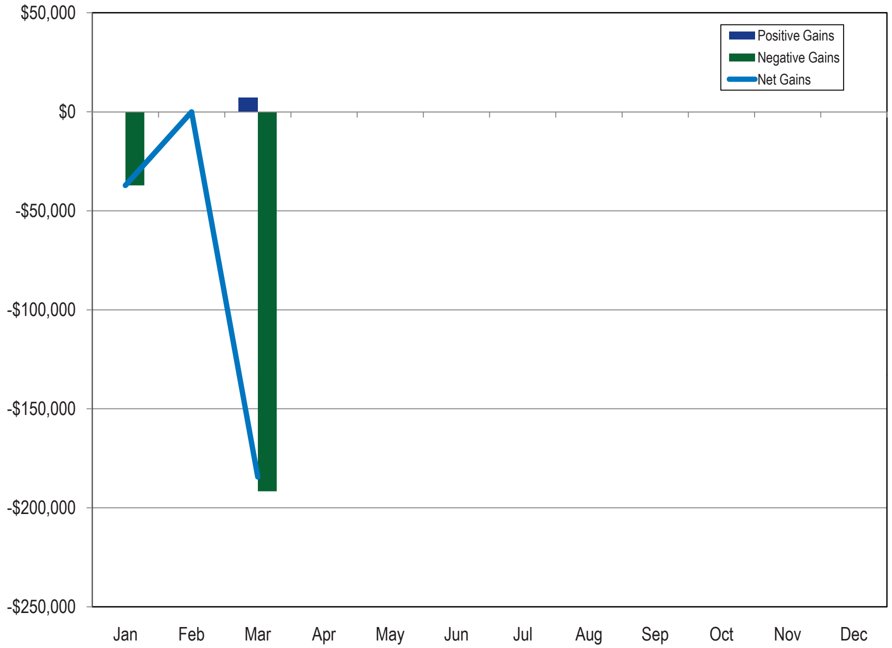
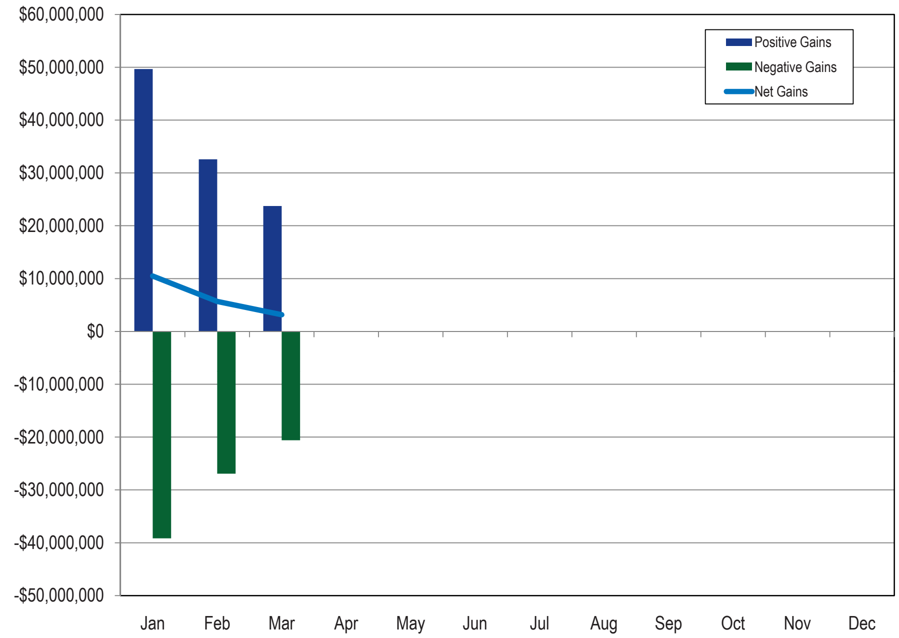


Figure 4-22 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Energy Market transaction: January through March 2011 (See 2010 SOM, Figure 4-21)



Interface Pricing Agreements with Individual Balancing Authorities

Table 4-13 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through March 2011 (See 2010 SOM, Table 4-13)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$43.46	$36.27	$39.29	$39.14	$4.17	($3.02)	$4.32	($2.87)
2011	$42.19	$36.24	$38.71	$38.71	$3.48	($2.47)	$3.48	($2.47)

Table 4-14 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2011 (See 2010 SOM, Table 4-14)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.04	$41.16	$38.71	$38.71	$1.32	$2.44
PEC	$40.71	$42.52	$38.71	$38.71	$2.00	$3.80
NCMPA	$40.65	$40.81	$38.71	$38.71	$1.93	$2.10

Figure 4-23 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2011 (See 2010 SOM, Figure 4-22)

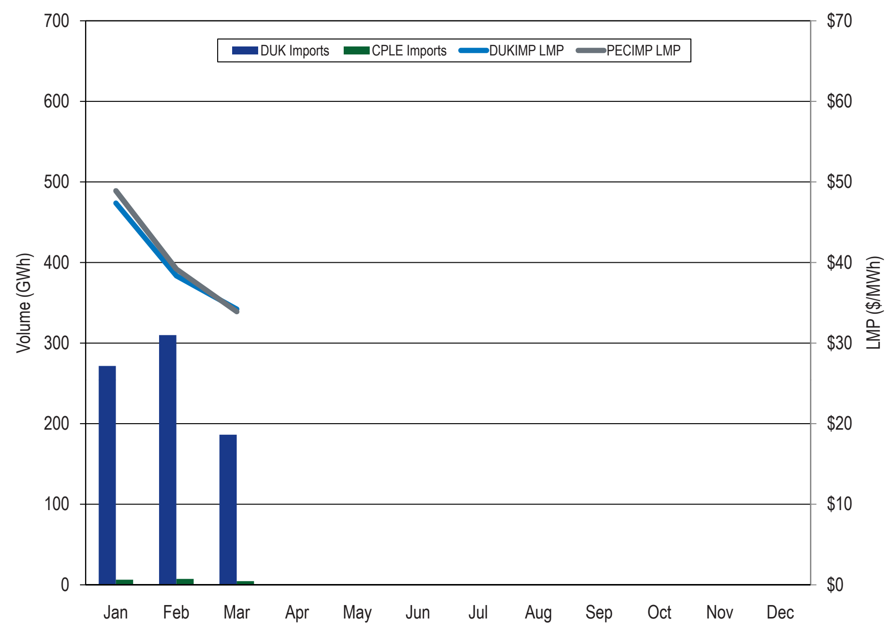


Figure 4-24 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2011 (See 2010 SOM, Figure 4-23)

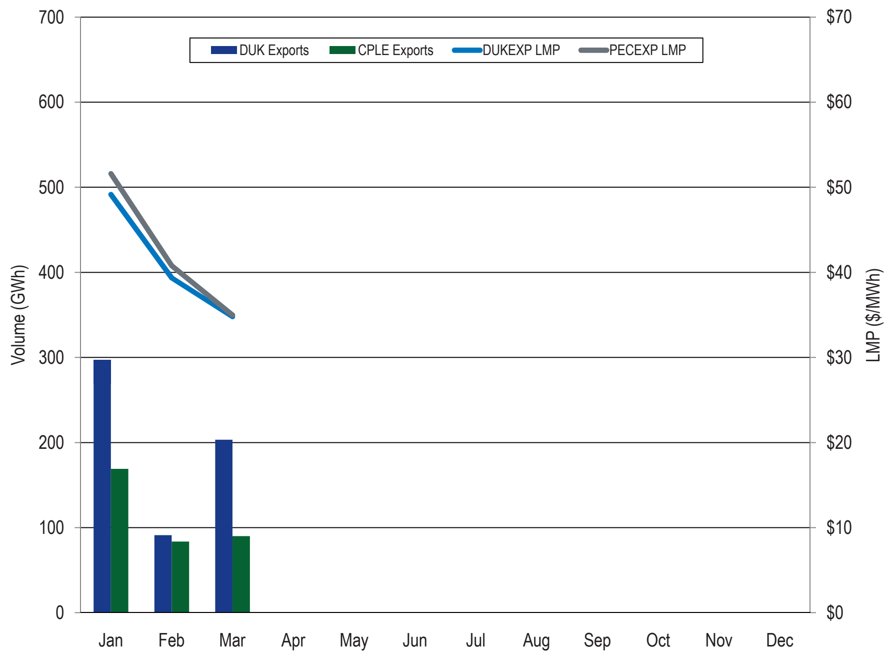


Table 4-15 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through March 2011 (See 2010 SOM, Table 4-15)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$41.53	$38.10	$38.32	$41.23	$3.21	($0.22)	$0.31	($3.13)
2007	$53.50	$45.01	$48.45	$47.76	$5.06	($3.44)	$5.75	($2.75)
2008	$63.44	$52.27	$56.26	$56.26	$7.17	($3.99)	$7.17	($3.99)
2009	$36.42	$32.05	$33.59	$33.59	$2.83	($1.54)	$2.83	($1.54)
2010	$44.42	$36.76	$39.40	$39.40	$4.64	($2.44)	$4.64	($2.44)
2011	$43.69	$36.97	$39.27	$39.27	$4.42	($2.30)	$4.42	($2.30)

Table 4-16 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2011 (See 2010 SOM, Table 4-16)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$40.86	$42.79	$39.27	$39.27	$1.59	$3.53
PEC	$42.38	$44.60	$39.27	$39.27	$3.11	$5.34
NCMPA	$41.81	$41.95	$39.27	$39.27	$2.54	$2.68

Figure 4-25 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2011 (See 2010 SOM, Figure 4-24)

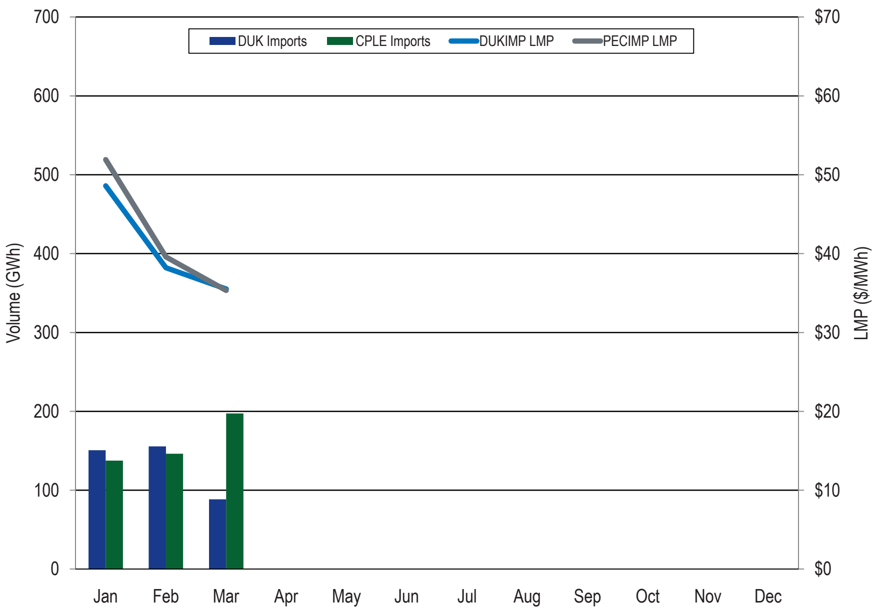
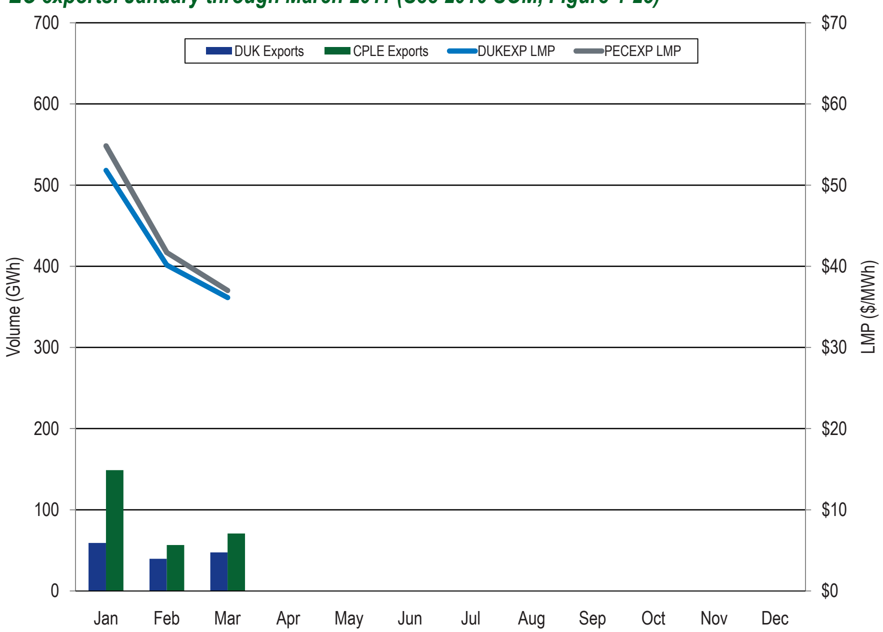
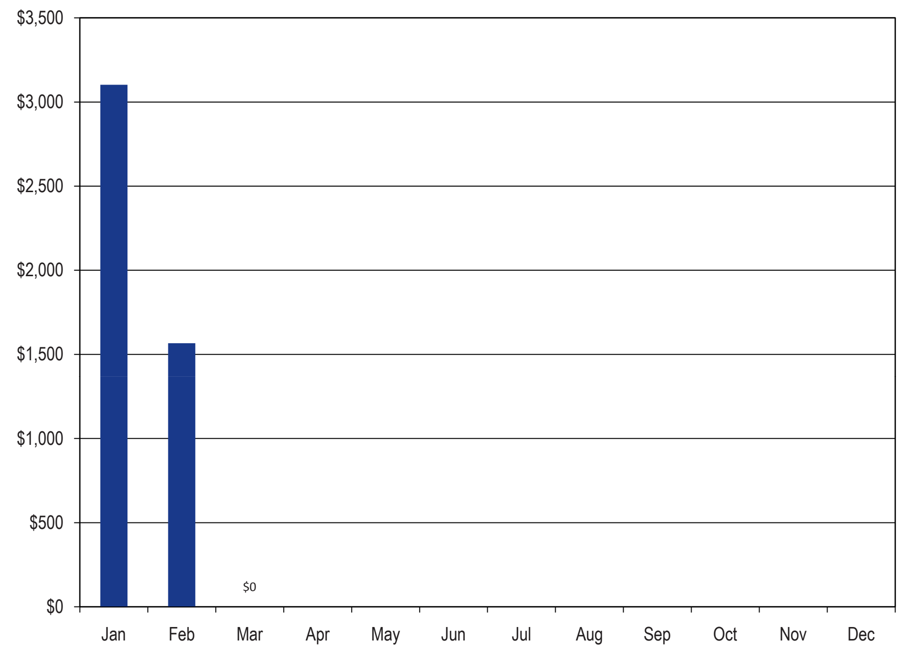


Figure 4-26 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2011 (See 2010 SOM, Figure 4-25)



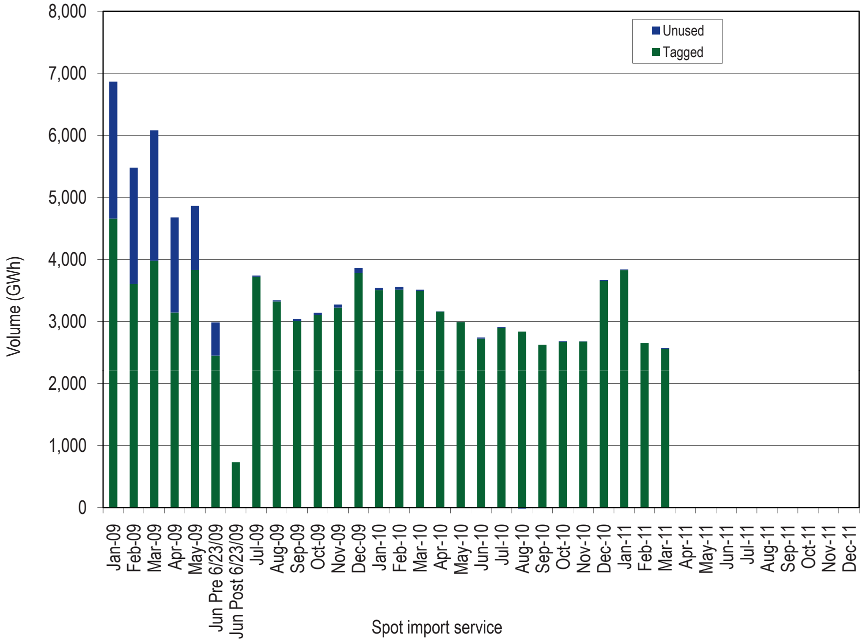
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-27 Monthly uncollected congestion charges: January through March 2011 (See 2010 SOM, Figure 4-26)



Spot Import

Figure 4-28 Spot import service utilization: Calendar year 2010 and January through March 2011 (See 2010 SOM, Figure 4-27)



SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can hedge their financial obligations in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first three months of calendar year 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

Table 5-1 The Capacity Market results were competitive

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

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

Highlights

- 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.

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

- Capacity in the RPM load management programs totals 10,810.1 MW for June 1, 2011.

- 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.

- 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.

- 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.

Summary Recommendations

- 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.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.[1]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the Second Incremental Auction is conducted if PJM determines that an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[4]

RPM prices are locational and may vary depending on transmission constraints.[5] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Offered MW in the 2011/2012 RPM Third Incremental Auction totaled 6,537.8 MW. The offered volumes came from uncleared internal generation offers from the 2011/2012 BRA (1,425.5 MW), new generation (283.0 MW), capacity modifications (cap mods) to existing generation resources (181.5 MW), additional UCAP due to improved EFORds since the BRA (1,829.7 MW), net replacements (-235.3 MW), locational UCAP transactions (-1,149.8 MW), ATSI integration generation (866.5 MW), imports (80.8 MW), DR offers (4,179.2 MW), EE offers (90.5 MW) less cleared capacity in the 2011/2012 First Incremental Auction (119.1 MW), ATSI FRR capacity plan commitments

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2011 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 See 126 FERC ¶ 61,275 (2009) at P 86.
3 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
4 See 126 FERC ¶ 61,275 (2009) at P 88.
5 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

(853.0 MW), Duquesne FRR capacity plan commitments (48.5 MW), a net change in FRR commitments (57.2 MW), a net change in exports (-18.4 MW), a net change in unoffered MW in the 2011/2012 BRA (-46.9 MW), and excused generation (1.3 MW).

- **Demand.** Buy bids in the 2011/2012 RPM Third Incremental Auction totaled 8,865.2 MW. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity.

- **Market Concentration.** For the 2014/2015 delivery year, all defined markets failed the preliminary market structure screen (PMSS).[6] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region shall be required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT). In the 2011/2012 Third Incremental Auction all participants in the total PJM market failed the three pivotal supplier (TPS) market structure test.[7,8] Offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[9,10,11]

- **Demand-Side and Energy Efficiency Resources.** Demand-side resources include demand resources (DR) and energy efficiency (EE) resources cleared in RPM auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the energy efficiency resource type is eligible to be offered in RPM auctions.[12] Of the 1,557.0 MW of cleared capacity in the 2011/2012 RPM Third Incremental Auction, 461.7 MW were DR offers and 76.4 MW were EE offers.

Market Conduct

- **2011/2012 RPM Third Incremental Auction.** Of the 398 generation resources which submitted offers, 214 resources elected the offer cap option of 1.1 times the BRA clearing price (53.8 percent). Unit-specific offer caps were calculated for no resources (0.0 percent). Offer caps of all kinds were calculated for 23 resources (5.8 percent), of which 21 were based on the technology specific default (proxy) avoidable cost rate (ACR) values. This was the first RPM Auction conducted under the revised RPM rules regarding mitigation and the definition of planned generation.[13]

Market Performance

2011/2012 RPM Third Incremental Auction

- **RTO.** There were 6,537.8 MW offered into the 2011/2012 Third Incremental Auction while buy bids totaled 8,865.2 MW. Cleared volumes in the RTO were 1,557.0 MW, resulting in an RTO clearing price of $5.00 per MW-day. The 4,980.8 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared capacity resources across the entire RTO will receive a total of $2.8 million based on the unforced MW cleared and the prices in the 2011/2012 RPM Third Incremental Auction.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd increased from 6.9 percent in the first three months of 2010 to 8.0 percent in the first three months of 2011. PJM Peak-Period Equivalent Forced Outage Rate Peak (EFORp) increased from 3.7 percent in the first three months of 2010 to 4.6 percent in the first three months of 2011.[14]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 87.4 percent in 2010 to 85.9 percent in 2011.

- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and

6 See "Preliminary Market Structure Screen Results for 2014/2015 RPM Base Residual Auction" (February 1, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf>.

7 Currently, there are 23 locational deliverability areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

8 PJM did not model any LDAs as constrained for the 2011/2012 delivery year.

9 OATT Attachment DD (Reliability Pricing Model) § 6.5.

10 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

11 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

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

13 See 134 FERC ¶ 61,065 (2011).

14 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the three months ending March 31, as downloaded from the PJM GADS database on April 21, 2011. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

procedures of the owning company. In the first three months of 2011, 10.8 percent of forced outages are classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first three months of calendar year 2011. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first three months of calendar year 2011.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[15,16,17,18,19,20,21]

RPM Capacity Market

Market Structure

Market Concentration

Preliminary Market Structure Screen

15 See "Analysis of the 2010/2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.

16 See "Analysis of the 2010/2011 RPM Third Incremental Auction" (December 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2010_2011_RPM_Third_Incremental_Auction_20101220.pdf>.

17 See "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.

18 See "Analysis of the 2011/2012 RPM First Incremental Auction" (January 6, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf>.

19 See "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

20 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

21 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" (October 4, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf>.

Table 5-2 Preliminary market structure screen results: 2010/2011 through 2014/2015 RPM Auctions (See 2010 SOM, Table 5-5)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail

Auction Market Structure

Table 5-3 RSI results: 2010/2011 through 2013/2014 RPM Auctions[22] (See 2010 SOM, Table 5-6)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2010/2011 Third Incremental Auction			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First Incremental Auction			
RTO	0.62	30	30
2011/2012 ATSI FRR Integration Auction			
RTO	0.07	21	21
2011/2012 Third Incremental Auction			
RTO	0.41	52	52
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3
2012/2013 ATSI FRR Integration Auction			
RTO	0.10	16	16

22 The RSI shown is the lowest RSI in the market.

Table 5-3 RSI results: 2010/2011 through 2013/2014 RPM Auctions (continued)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 First Incremental Auction			
RTO	0.60	25	25
EMAAC	0.00	2	2
2013/2014 BRA			
RTO	0.59	87	87
MAAC/SWMAAC	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.00	2	2
Pepco	0.00	1	1

Demand-Side Resources

Table 5-4 RPM load management statistics by LDA: June 1, 2009 to June 1, 2013[23,24] (See 2010 SOM, Table 5-8)

	UCAP (MW)							
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
DR cleared	892.9	813.9			356.3			
DR net replacements	(474.7)	(466.9)			(102.1)			
ILR certified	6,481.5	3,081.0			519.3			
RPM load management @ 01-June-2009	6,899.7	3,428.0			773.5			
DR cleared	962.9					14.9		
DR net replacements	(516.3)					(14.9)		
ILR certified	8,236.4					97.2		
RPM load management @ 01-June-2010	8,683.0					97.2		
DR cleared	1,826.6							
EE cleared	76.4							
DR net replacements	(221.2)							
EE net replacements	0.0							
ILR certified	9,128.3							
RPM load management @ 01-June-2011	10,810.1							
DR cleared	7,524.7		4,897.5	1,807.4		66.1	72.2	
EE cleared	568.9		179.9	20.0		0.0	0.9	
DR net replacements	0.0		0.0	0.0		0.0	0.0	
EE net replacements	0.0		0.0	0.0		0.0	0.0	
RPM load management @ 01-June-2012	8,093.6		5,077.4	1,827.4		66.1	73.1	
DR cleared	9,281.9		5,871.1	2,461.3				547.3
EE cleared	679.4		152.0	23.9				35.8
DR net replacements	0.0		0.0	0.0				0.0
EE net replacements	0.0		0.0	0.0				0.0
RPM load management @ 01-June-2013	9,961.3		6,023.1	2,485.2				583.1

23 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.
24 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

Table 5-5 RPM load management cleared capacity and ILR: 2007/2008 through 2013/2014[25,26] (See 2010 SOM, Table 5-9)

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,823.2	9,128.3
2012/2013	7,286.5	7,524.7	551.3	568.9	0.0	0.0
2013/2014	8,977.8	9,281.9	658.5	679.4	0.0	0.0

Table 5-6 RPM load management statistics: June 1, 2007 to June 1, 2013[27,28] (See 2010 SOM, Table 5-10)

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,663.2	11,031.3	(213.8)	(221.2)	0.0	0.0	10,449.4	10,810.1
01-Jun-12	7,837.8	8,093.6	0.0	0.0	0.0	0.0	7,837.8	8,093.6
01-Jun-13	9,636.3	9,961.3	0.0	0.0	0.0	0.0	9,636.3	9,961.3

25 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.
26 FRR committed load management resources are not included in this table.
27 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. The ILR MW for 2011/2012 are certified as of May 6, 2011, but are not final until June 1, 2011 as some of the ILR can be withdrawn by May 31, 2011. Effective the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions.
28 FRR committed load management resources are not included in this table.

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2010/2011 through 2011/2012 RPM Auctions (See 2010 SOM, Table 5-11)

	2010/2011 BRA		2010/2011 Third Incremental Auction		2011/2012 BRA		2011/2012 First Incremental Auction		2011/2012 ATSI Integration Auction		2011/2012 Third Incremental Auction	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	370	33.5%	7	2.3%	299	26.6%	44	34.1%	57	40.4%	21	5.3%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	18	14.0%	4	2.8%	0	0.0%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	1	0.8%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%	3	2.1%	2	0.5%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	3	2.3%	0	0.0%	0	0.0%
Generation resources with calculated offer caps	532	48.1%	9	2.9%	470	41.8%	68	52.8%	64	45.3%	23	5.8%
Uncapped planned generators	15	1.4%	0	0.0%	20	1.8%	1	0.8%	5	3.5%	27	6.8%
Generation resources with uncapped planned uprates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1	0.3%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	193	63.7%	NA	NA	NA	NA	52	36.9%	214	53.7%
Generation price takers	557	50.5%	101	33.4%	635	56.4%	60	46.4%	20	14.3%	133	33.4%
Generation resources offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%	141	100.0%	398	100.0%
Demand resources offered	23		34		37		0		46		74	
Energy efficiency resources offered	0		0		0		0		1		33	
Total capacity resources offered	1,127		337		1,162		129		188		505	

Table 5-8 ACR statistics: 2012/2013 through 2013/2014 RPM Auctions (See 2010 SOM, Table 5-12)

	2012/2013 BRA		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2013/2014 BRA	
Calculation Type	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered	Number of Resources	Percent of Generation Resources Offered
Default ACR selected	465	41.0%	117	67.6%	92	56.8%	580	49.6%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	92	7.9%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	15	1.3%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	6	0.5%
Default ACR and opportunity cost input	14	1.2%	0	0.0%	0	0.0%	7	0.6%
Generation resources with calculated offer caps	607	53.5%	131	75.7%	108	66.6%	700	59.9%
Uncapped planned generators	11	1.0%	0	0.0%	17	10.5%	20	1.7%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA
Generation price takers	515	45.5%	16	9.3%	37	22.9%	450	38.4%
Generation resources offered	1,133	100.0%	173	100.0%	162	100.0%	1,170	100.0%
Demand resources offered	233		46		77		426	
Energy efficiency resources offered	53		2		3		128	
Total capacity resources offered	1,419		221		242		1,724	

Market Performance

Table 5-9 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions (See 2010 SOM, Table 5-14)

	RPM Clearing Price ($ per MW-day)							
	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third Incremental Auction	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85
2009/2010 BRA	$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33
2009/2010 Third Incremental Auction	$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29
2010/2011 Third Incremental Auction	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
2011/2012 BRA	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00
2011/2012 First Incremental Auction	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
2011/2012 ATSI FRR Integration Auction	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14

Table 5-10 RPM revenue by type: 2007/2008 through 2013/2014[29,30] (See 2010 SOM, Table 5-15)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$262,109,171	$540,278,140	$1,025,067,095
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,155,913	$18,323,569	$29,619,294
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,115,246	$31,191,272	$475,437,338
Coal existing	$1,022,993,505	$1,845,819,870	$2,420,481,808	$2,662,434,386	$1,595,707,479	$1,015,782,743	$1,720,750,315	$12,283,970,106
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,413,749	$12,493,918	$53,260,564
Gas existing	$1,514,060,691	$1,949,645,918	$2,326,304,914	$2,632,336,161	$1,607,317,731	$1,115,914,101	$1,885,036,661	$13,030,616,178
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$75,945,518	$165,431,441	$441,284,226
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$178,866,339	$308,348,743	$2,070,257,920
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$761,838,276	$1,341,583,669	$8,818,477,107
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,912,313	$619,307,680	$3,640,282,698
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$24,264,473
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,835,364	$43,611,119	$241,858,290
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,425	$2,411,690	$4,080,046
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$944,720	$947,905	$1,959,603
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$779,404	$1,321,010	$8,614,130
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$3,771,957	$11,859,958	$50,537,847
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,863,627,224	$6,708,567,045	$42,199,586,913

29 A resource classified as "new/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/reactivated" for its initial offer and all its subsequent offers in RPM auctions.
30 The results for the ATSI Integrations Auctions are not included in this table.

Figure 5-1 History of capacity prices: Calendar year 1999 through 2013[31] (See 2010 SOM, Figure 5-1)

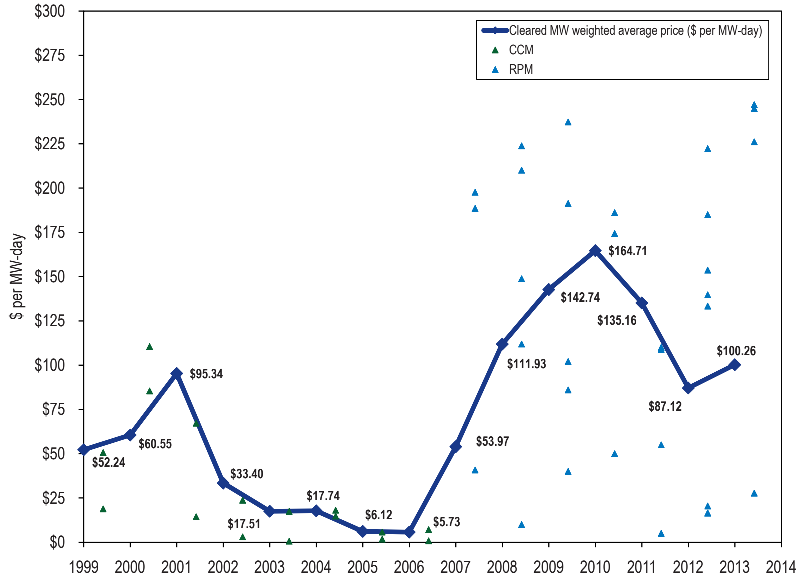


Table 5-11 RPM cost to load: 2010/2011 through 2013/2014[32,33,34] (See 2010 SOM, Table 5-16)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2010/2011			
RTO	$182.85	129,332.6	$8,631,690,057
DPL	$187.04	4,515.5	$308,271,379
2011/2012			
RTO	$116.23	133,815.3	$5,692,526,949
2012/2013			
RTO	$16.46	69,339.1	$416,582,379
MAAC	$129.75	31,423.4	$1,488,172,945
EMAAC	$139.40	21,027.5	$1,069,900,228
DPL	$168.10	4,521.4	$277,417,279
PSEG	$153.55	12,446.4	$697,567,823
2013/2014			
RTO	$27.73	85,918.0	$869,614,741
MAAC	$223.85	23,944.0	$1,956,350,506
EMAAC	$240.41	38,634.3	$3,390,146,303
Pepco	$236.93	7,996.7	$691,550,218

31 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2013 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

32 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

33 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

34 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 delivery year, the Final UCAP Obligation is determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after the final incremental auction. The 2011/2012, 2012/2013, and 2013/2014 Net Load Prices are not finalized. The 2012/2013 and 2013/2014 Obligation MW are not finalized.

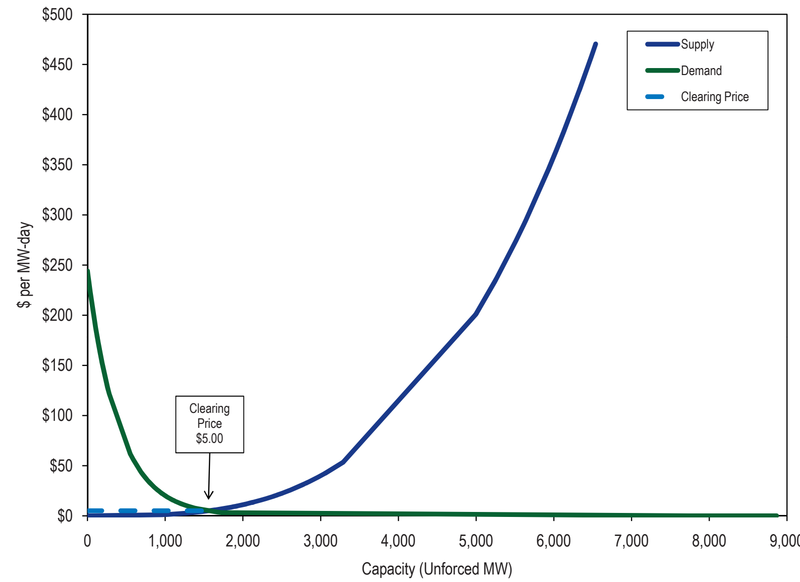
2011/2012 RPM Third Incremental Auction

RTO

Table 5-12 RTO offer statistics: 2011/2012 RPM Third Incremental Auction (See 2010 SOM, Table 5-19)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,388.2	2,268.1	
DR	4,040.0	4,179.2	
EE	87.8	90.5	
Total	6,516.0	6,537.8	8,865.2
Cleared in RTO	1,575.0	1,557.0	1,557.0
Cleared in LDAs	0.0	0.0	0.0
Total cleared	1,575.0	1,557.0	1,557.0
Uncleared in RTO	4,941.0	4,980.8	7,308.2
Uncleared in LDAs	0.0	0.0	0.0
Total uncleared	4,941.0	4,980.8	7,308.2
Resource clearing price ($ per MW-day)		$5.00	

Figure 5-2 RTO market supply/demand curves: 2011/2012 RPM Third Incremental Auction[35] (New figure)



35 The supply and demand curves have been smoothed using a statistical technique that fits a smooth curve to the underlying data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. The supply curve includes all offered MW, and the demand curve includes all bid MW while the prices reflect the smoothing method.

Generator Performance

Generator Performance Factors

Figure 5-3 PJM equivalent outage and availability factors: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-4)

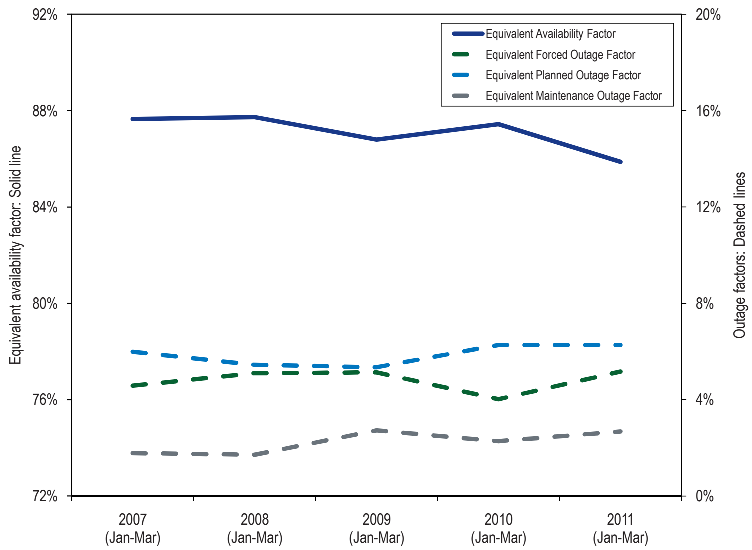
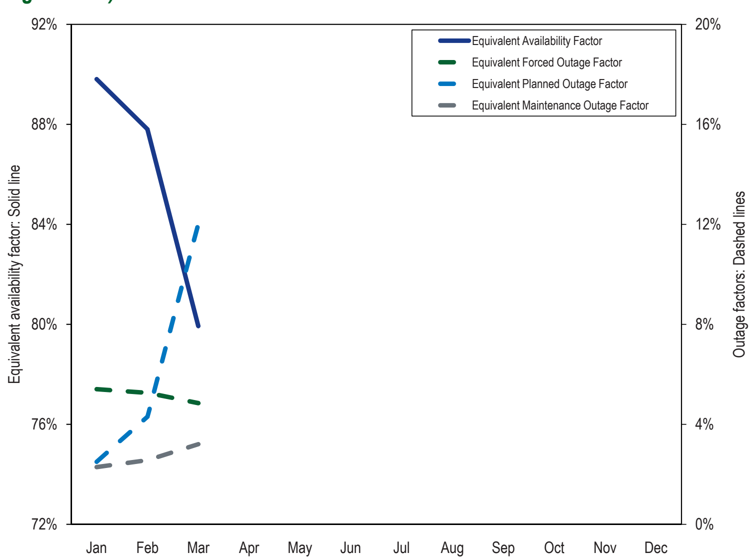
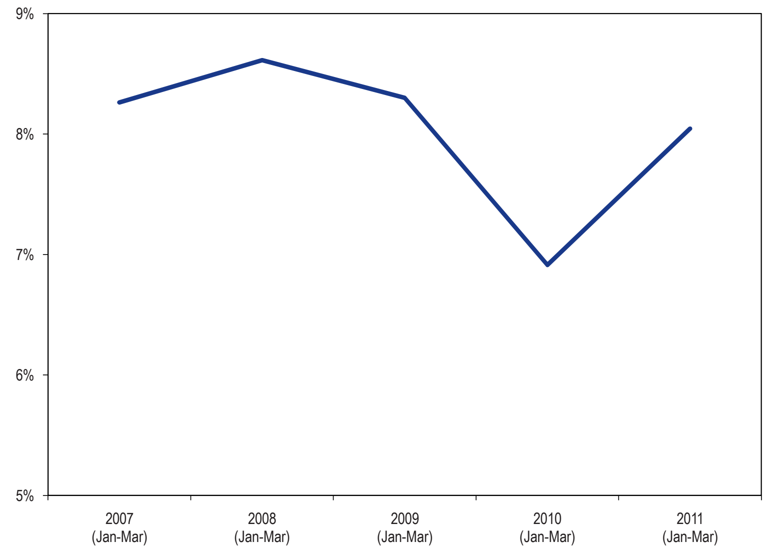


Figure 5-4 Generator performance factors: January through March 2011 (See 2010 SOM, Figure 5-10)



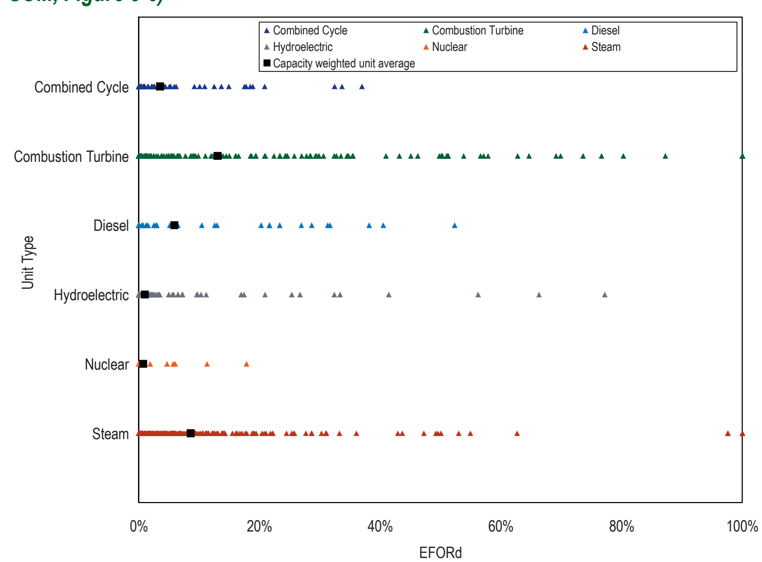
Generator Forced Outage Rates

Figure 5-5 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-5)



Distribution of EFORd

Figure 5-6 Distribution of EFORd data by unit type: January through March 2011 (See 2010 SOM, Figure 5-6)



Components of EFORd

Table 5-13 PJM EFORd data: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Table 5-20)

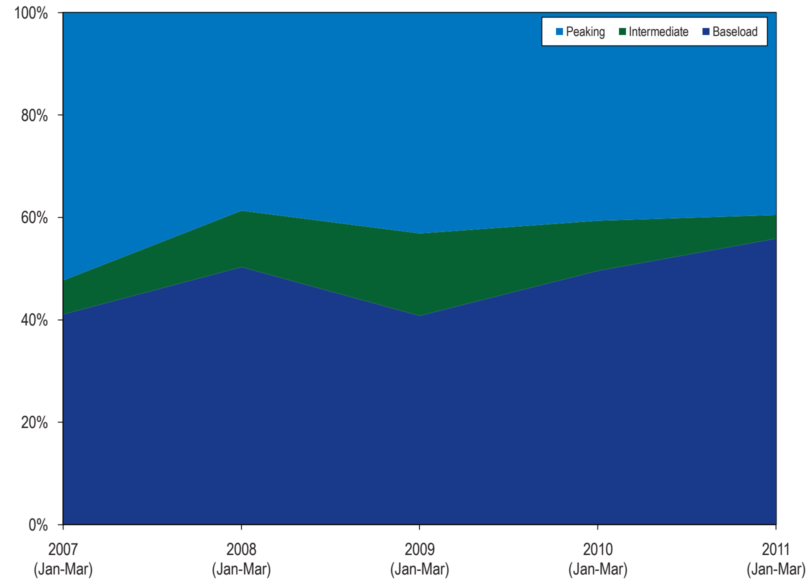
	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	8.7%	4.6%	5.3%	3.5%	3.5%
Combustion Turbine	20.2%	16.0%	13.9%	13.1%	8.5%
Diesel	9.1%	10.1%	8.2%	5.9%	6.6%
Hydroelectric	1.9%	2.9%	1.9%	1.0%	2.2%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%
Steam	8.0%	10.4%	9.5%	8.6%	12.1%
Total	8.3%	8.6%	8.3%	6.9%	8.0%

Table 5-14 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2007 to 2011[36] (January through March) (See 2010 SOM, Figure 5-21)

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	Change in 2011 from 2010
Combined Cycle	1.0	0.6	0.6	0.4	0.4	(0.0)
Combustion Turbine	3.2	2.5	2.2	2.1	1.4	(0.7)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.0
Nuclear	0.1	0.3	0.7	0.1	0.3	0.2
Steam	3.9	5.2	4.7	4.2	5.9	1.6
Total	8.3	8.6	8.3	6.9	8.0	1.1

Duty Cycle and EFORd

Figure 5-7 Contribution to EFORd by duty cycle: Calendar years 2007 to 2011 (January through March) (See 2010 SOM, Figure 5-7)



36 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Forced Outage Analysis

Table 5-15 Contribution to EFOF by unit type by cause: January through March 2011 (See 2010 SOM, Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	7.6%	0.0%	0.0%	0.0%	0.0%	29.0%	24.2%
Economic	1.7%	10.7%	0.0%	3.1%	0.0%	10.7%	9.3%
Boiler Piping System	44.9%	0.0%	0.0%	0.0%	0.0%	5.8%	8.3%
Electrical	5.1%	16.2%	0.0%	5.4%	26.1%	5.9%	7.3%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	7.5%	6.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.3%	3.5%
Miscellaneous (Generator)	12.3%	5.1%	2.5%	0.2%	0.0%	2.4%	3.1%
Feedwater System	1.3%	0.0%	0.0%	0.0%	0.0%	3.4%	2.9%
Cooling System	0.0%	0.0%	0.0%	0.0%	10.4%	1.8%	2.0%
Auxiliary Systems	3.3%	19.0%	0.0%	0.6%	0.0%	1.1%	1.9%
Condensate System	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	1.8%
Condensing System	0.1%	0.0%	0.0%	0.0%	1.7%	2.0%	1.7%
Fuel Quality	0.0%	0.0%	1.8%	0.0%	0.0%	2.0%	1.6%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	30.4%	0.0%	1.6%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.6%
Personnel or Procedure Errors	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Miscellaneous Boiler Tube Problems	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.5%
Boiler Fuel Supply to Bunker	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	1.4%
All Other Causes	23.4%	49.0%	95.6%	90.7%	31.4%	12.3%	16.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-16 Contributions to Economic Outages: January through March 2011 (See 2010 SOM, Table 5-23)

	Contribution to Economic Reasons
Lack of fuel (OMC)	95.6%
Lack of fuel (Non-OMC)	2.6%
Other economic problems	1.0%
Lack of water (Hydro)	0.4%
Fuel conservation	0.3%
Total	100.0%

Table 5-17 Contribution to EFOF by unit type: January through March 2011 (See 2010 SOM, Table 5-24)

	EFOF	Contribution to EFOF
Combined Cycle	1.3%	8.0%
Combustion Turbine	2.2%	4.1%
Diesel	3.8%	0.2%
Hydroelectric	0.7%	1.3%
Nuclear	0.7%	5.3%
Steam	6.8%	81.2%
Total	4.0%	100.0%

Outages Deemed Outside Management Control

Table 5-18 OMC Outages: January through March 2011 (See 2010 SOM, Table 5-25)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Economic	83.0%	8.9%
Electrical	7.2%	0.8%
Catastrophe	6.1%	0.7%
Miscellaneous (External)	3.2%	0.3%
Power Station Switchyard	0.5%	0.1%
Total	100.0%	10.8%

Table 5-19 PJM EFORd vs. XEFORd: January through March 2011 (See 2010 SOM, Table 5-26)

	EFORd	XEFORd	Difference
Combined Cycle	3.5%	3.2%	0.3%
Combustion Turbine	8.5%	6.4%	2.1%
Diesel	6.6%	3.9%	2.7%
Hydroelectric	2.2%	1.8%	0.4%
Nuclear	1.6%	1.6%	0.0%
Steam	12.1%	9.3%	2.8%
Total	8.0%	6.3%	1.7%

Components of EFORp

Table 5-20 Contribution to EFORp by unit type (Percentage points): Calendar years 2010 to 2011 (January through March) (See 2010 SOM, Table 5-27)

	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	0.2	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.0	0.1
Nuclear	0.2	0.4
Steam	2.9	3.4
Total	3.7	4.6

Table 5-21 PJM EFORp data by unit type: Calendar years 2010 to 2011 (January through March) (See 2010 SOM, Table 5-28)

	2010 (Jan-Mar)	2011 (Jan-Mar)
Combined Cycle	1.9%	2.4%
Combustion Turbine	2.3%	2.6%
Diesel	3.7%	2.4%
Hydroelectric	0.5%	2.0%
Nuclear	1.0%	2.3%
Steam	5.9%	7.0%
Total	3.7%	4.6%

EFORd, XEFORd and EFORp

Table 5-22 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through March 2011 (See 2010 SOM, Table 5-29)

	EFORd	XEFORd	EFORp
Combined Cycle	0.4	0.4	0.3
Combustion Turbine	1.4	1.0	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.3	0.3	0.4
Steam	5.9	4.5	3.4
Total	8.0	6.3	4.6

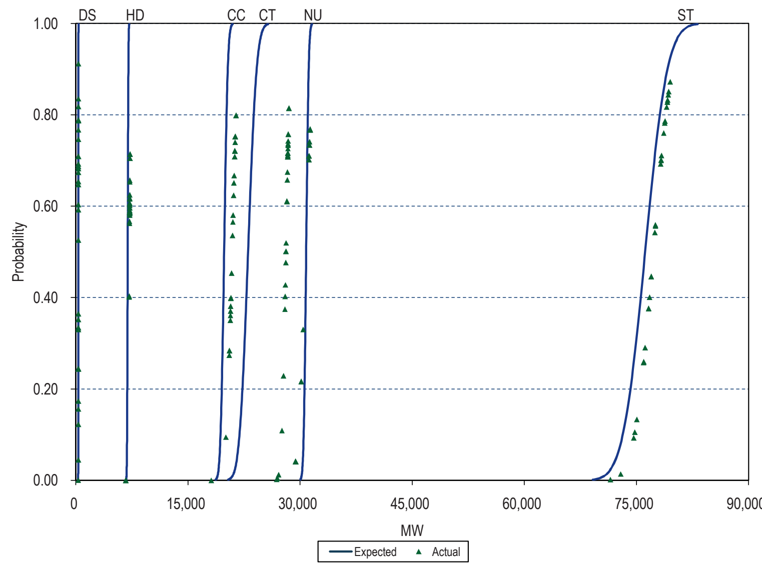
Table 5-23 PJM EFORd, XEFORd and EFORp data by unit type: January through Ma rch 2011[37] (See 2010 SOM, Table 5-30)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.5%	3.2%	2.4%	0.3%	1.0%
Combustion Turbine	8.5%	6.4%	2.6%	2.1%	5.9%
Diesel	6.6%	3.9%	2.4%	2.7%	4.2%
Hydroelectric	2.2%	1.8%	2.0%	0.4%	0.2%
Nuclear	1.6%	1.6%	2.3%	0.0%	(0.7%)
Steam	12.1%	9.3%	7.0%	2.8%	5.0%
Total	8.0%	6.3%	4.6%	1.7%	3.4%

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

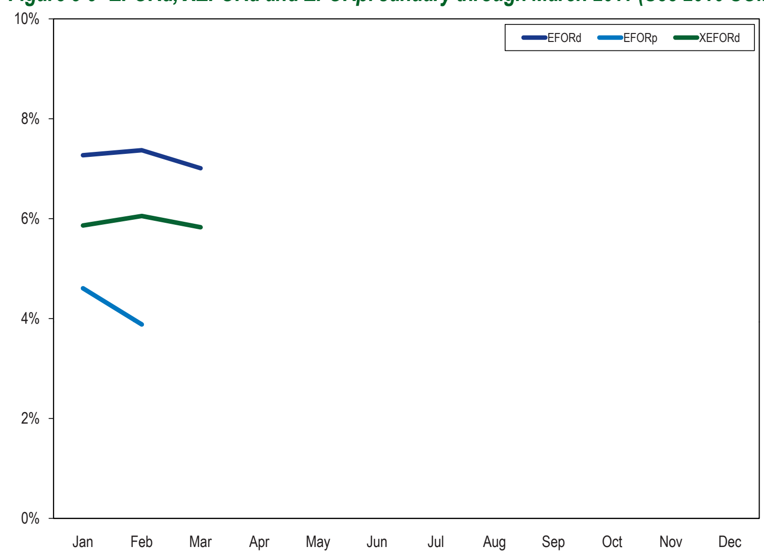
Comparison of Expected and Actual Performance

Figure 5-8 Distribution of EFORd data by unit type: January through March 2011 (See 2010 SOM, Figure 5-8)



Performance by Month

Figure 5-9 EFORd, XEFORd and EFORp: January through March 2011 (See 2010 SOM, Figure 5-9)



SECTION 6 - ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See the *2010 State of the Market Report for PJM*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2010.

The purpose of the Day-Ahead Scheduling Reserve (DASR) market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.[3]

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2011.

Table 6-1 The Regulation Market results were not competitive[4]

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

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

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

4 As Table 6-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

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 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 6-2 The Synchronized Reserve Markets results were competitive

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

- The 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 6-3 The Day-Ahead Scheduling Reserve Market results were competitive

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

- The 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.

Highlights

- 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.

- 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.

- 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.

- 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.

- 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.[5] 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.

- 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.

- 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.

Summary Recommendations

- 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.

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

Overview

Regulation Market

The PJM Regulation Market in the first three months of 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the three pivotal supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits.

Market Structure

- **Supply.** In the first three months of 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in the first three months of 2011. The ratio of eligible regulation offered to regulation required averaged 3.09 for the first three months of 2011. This is a five percent increase over the first three months of 2010 when the ratio was 2.94.

- **Demand.** The on-peak regulation requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand for the first three months of 2011 was 893 MW (830 MW off peak, and 964 MW on peak). This is a 3 MW decrease in the average hourly regulation demand for the first three months of 2010 (837 MW off peak, and 959 MW on peak).

- **Market Concentration.** During the first three months of 2011, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1785 which is classified as "moderately concentrated."[6] The minimum hourly HHI was 916 and the maximum hourly HHI was 3550. The largest hourly market share in any single hour was 54 percent, and 89 percent of all hours had a maximum market share greater than

6 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

20 percent.[7] In the first three months of 2011, 94 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in the first three months of 2011 was characterized by structural market power in 94 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[8] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then re-solved.

  As part of the changes to the Regulation Market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50.[9] The impact of this change was to increase cost based offer prices compared to what they would have been with the $7.50 maximum margin.

Market Performance

- **Price.** For the PJM Regulation Market in the first three months of 2011, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $11.51 per MW. This was a decrease of $6.33, or 35 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $5.43 from $30.69 per MW for the first three months of 2010, to $24.83, or 19 percent. The Regulation Market clearing price was only 46 percent of the total regulation cost per MW.

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made no changes to the Synchronized Reserve Market structure during the first three months of 2011. In 2009, PJM made a structural change to address the problem of excessive after-market Tier 2 added by dispatchers when the market did not adequately provide for Tier 2 synchronized reserve in constrained, heavy-load, and/or off-peak hours. The structural change was to change the transfer interface which defines the Eastern sub-zone from Bedington—Black Oak to AP South. In addition, PJM made a non-structural change to address the same issue by changing the Tier 1 transfer capability of the AP South interface from 70 percent to 15 percent. The AP South interface transfer capability is a parameter (changeable by PJM Market Operations) specifying the percent of Tier 1 synchronized reserve west of AP South that can be considered available to the Mid-Atlantic Subzone. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. In December, 2010 PJM lowered the transfer capability further to five percent. This had the effect of increasing the amount of Tier 2 synchronized reserve that had to be cleared in the Mid Atlantic Subzone, effectively segregating the RFC Synchronized Reserve Zone and Mid-Atlantic Subzone into two markets. Synchronized reserves added out of market were one percent of all synchronized reserves during the first three months of 2011, down from two percent for the same time period in 2010. Opportunity cost payments accounted for 17 percent of total costs during the first three months of 2011 compared to 25 percent for 2010.

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

8 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 39.

9 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** In the first three months of 2011 the offered and eligible excess supply ratio was 1.05 for the Mid-Atlantic Subzone.[10] For the first three months of 2010 the eligible excess supply ratio in the Mid Atlantic subzone was 1.25. For the RFC zone, the excess supply ratio was 3.09. For the first three months of 2010 the eligible excess supply ratio RFC zone was 2.33. The excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are low cost, and their participation in this market lowers overall Synchronized Reserve prices.

- **Demand.** PJM made several changes to the hourly required synchronized reserve requirement in 2010. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW. The synchronized reserve requirement for the Mid Atlantic Subzone remained at 1,300 MW for the first three months of 2011. During the first three months of 2010 the synchronized reserve requirement for the Mid-Atlantic Subzone was 1,150 MW. For the RFC zone the synchronized reserve requirement remained at its 2010 level of 1,350 MW. During the first three months of 2010 the synchronized reserve requirement was 1,320 MW. The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011 for double spinning.

  For the first three months of 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in all but three hours (99.9 percent). In the first three months of 2010 a Tier 2 synchronized reserve market was cleared in 1,877 hours (89 percent).The reduction of the transfer capability to five percent across the AP South interface required that more synchronized reserve be provided within the Mid Atlantic Subzone. For the first three months of 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 742 MW. For the first three months of 2010 the average required Tier 2 synchronized reserve was 450 MW. This 65 percent increase in required tier 2 synchronized reserves was a result of the reduction in the transfer capacity of the AP South interface.

10 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

  Synchronized reserves added out of market were one percent of all Mid-Atlantic Subzone synchronized reserves in the first three months of 2011. Synchronized reserves added out of market were also one percent of all Mid-Atlantic Subzone synchronized reserves in the first three months of 2010.

  Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, no hours cleared a Tier 2 Synchronized Reserve Market in the RFC during the first three months of 2011. Similarly a Tier 2 Synchronized Reserve Market was not cleared for the Southern Synchronized Reserve Zone during the first three months of 2011.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone for the first three months of 2011 was 2562, which is classified as "highly concentrated."[11] For purchased synchronized reserve (cleared plus added) the HHI was 2606. In the first three months of 2011, 46 percent of hours had a maximum market share greater than 40 percent, compared to 58 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in the first three months of 2011, 88 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the same period of 2010, 59 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in the first quarter of 2011 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

11 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Total MW of demand side resources increased in the first quarter of 2011 over first quarter 2010 (from 50,008 MW to 80,540 MW) but their share of the total Synchronized Reserve Market declined from 18.7 percent to 16.0 percent. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in only one percent of hours in the first three months of 2011 compared to four percent of hours on the first three months of 2010.

Market Performance

- **Price.** The load weighted, average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $10.96 per MW in the first three months of 2011, a $3.93 per MW increase from the same period in 2010. The market clearing price was 83 percent of the total synchronized reserve cost per MW in the first three months of 2011, up from 63 percent in the same time period of 2010. This reduction in the dispatch of out of market synchronized reserves was a result of lowering the AP South transfer capability metric to five percent.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in the first three months of 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[12] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[13] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

12 See 117 FERC ¶ 61,331 (2006).
13 See PJM. "Manual 13: Emergency Operations," Revision 42, (January 21, 2011); pp 11-12.

Market Structure

- **Concentration.** In the first three months of 2011, no hours in the DASR market failed the three pivotal supplier test.

- **Demand.** In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010. [14] DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement is now 7.11 percent. The DASR MW purchased averaged 5,731 MW per hour for the first three months of 2011, a small increase from 5,695 MW per hour during the same period in 2010.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. The first three months of 2011 continued a pattern that has existed since the inception of the DASR Market. Five percent of units offered at $50 or more with four percent offering at more than $900, in a market with an average clearing price of $0.02 and a maximum clearing price of $1.00. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[15] Units that do not offer will have their offers set to $0/MW.

- **DSR.** Demand side resources do participate in the DASR Market, but remain insignificant. No demand resource cleared the DASR Market in the first three months of 2011.

Market Performance

- **Price.** In the first three months of 2011, the load weighted price of DASR was $0.02 per MW. In the first three months of 2010, the load weighted price of DASR was $0.05 per MW.

14 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
15 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[16]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. For the first three months of 2011, charges were $2.86 million. This is 22 percent higher than the first three months of 2010, when total black start service charges were $2.34 million. There was substantial zonal variation.

Ancillary Services costs per MW of load: 2001 - 2011

Table 6-4 shows PJM ancillary services costs from 2001 through the first three months of 2011 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

16 OATT Schedule 1 § 1.3BB.

Table 6-4 History of ancillary services costs per MW of Load: 2001 through the first three months of 2011

Year	Regulation	Scheduling, System Control, and Dispatch	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22		$1.08
2002	$0.46	$0.54	$0.22	$0.00	$0.74
2003	$0.50	$0.62	$0.24	$0.16	$0.86
2004	$0.50	$0.62	$0.26	$0.12	$0.92
2005	$0.80	$0.50	$0.26	$0.12	$0.96
2006	$0.52	$0.52	$0.30	$0.08	$0.44
2007	$0.64	$0.52	$0.30	$0.06	$0.62
2008	$0.71	$0.39	$0.32	$0.08	$0.62
2009	$0.34	$0.32	$0.36	$0.05	$0.48
2010	$0.35	$0.38	$0.40	$0.07	$0.74
2011	$0.27	$0.39	$0.39	$0.12	$0.71

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[17]

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

The MMU concludes that the DASR Market results were competitive in the first three months of 2011.

17 The *2009 State of the Market Report for PJM* provided the basis for this recommendation. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three months of 2011 as a result of the identified market design changes and their implementation. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three months of 2011. The MMU concludes that the DASR Market results were competitive in the first three months of 2011.

Regulation Market

Market Structure

Supply

Table 6-5 PJM regulation capability, daily offer[18] and hourly eligible: January through March, 2011 (See 2010 SOM, Table 6-5)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,847	5,790	74%	2,754	35%
Off Peak	7,847			2,545	32%
On Peak	7,847			2,990	38%

Demand

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March, 2011 (See 2010 SOM, Table 6-6)

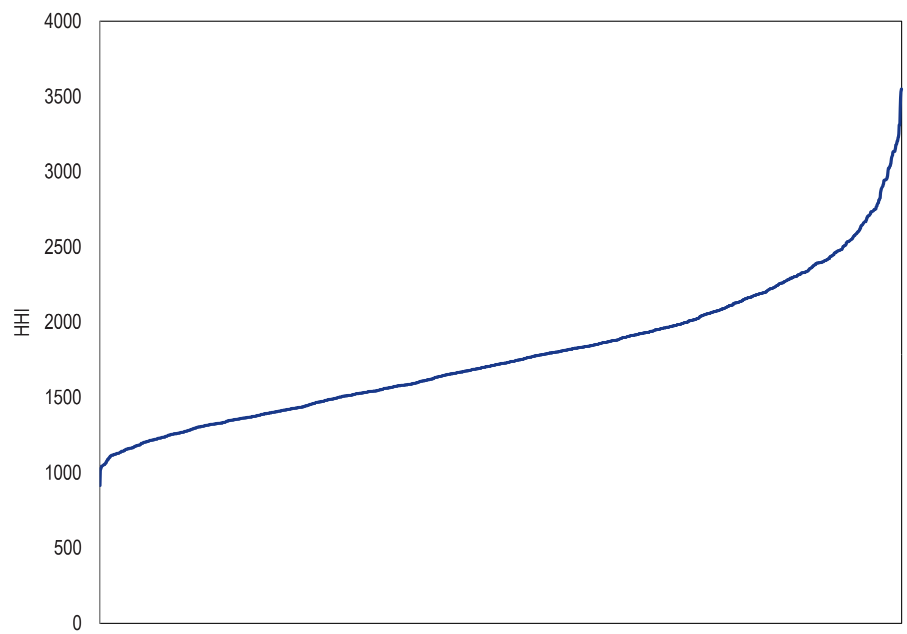
Month	Average Required Regulation (MW)	Ratio of Supply To Requirement
Jan	960	3.19
Feb	897	3.06
Mar	823	3.01

Market Concentration

Table 6-7 PJM cleared regulation HHI: January through March, 2011 (See 2010 SOM, Table 6-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January through March, 2011	916	1785	3550

Figure 6-1 PJM Regulation Market HHI distribution: January 1 through March 31, 2011 (See 2010 SOM, Figure 6-1)



18 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Table 6-8 Highest annual average hourly Regulation Market shares: January through March, 2011 (See 2010 SOM, Table 6-8)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	27%
2	17%
3	13%
4	11%
5	9%

Table 6-9 Regulation market monthly three pivotal supplier results: January through March, 2011 (See 2010 SOM, Table 6-9)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	95%
Feb	93%
Mar	94%

Market Conduct

Offers

Figure 6-2 Off peak and on peak regulation levels: January through March, 2011 (See 2010 SOM, Figure 6-2)

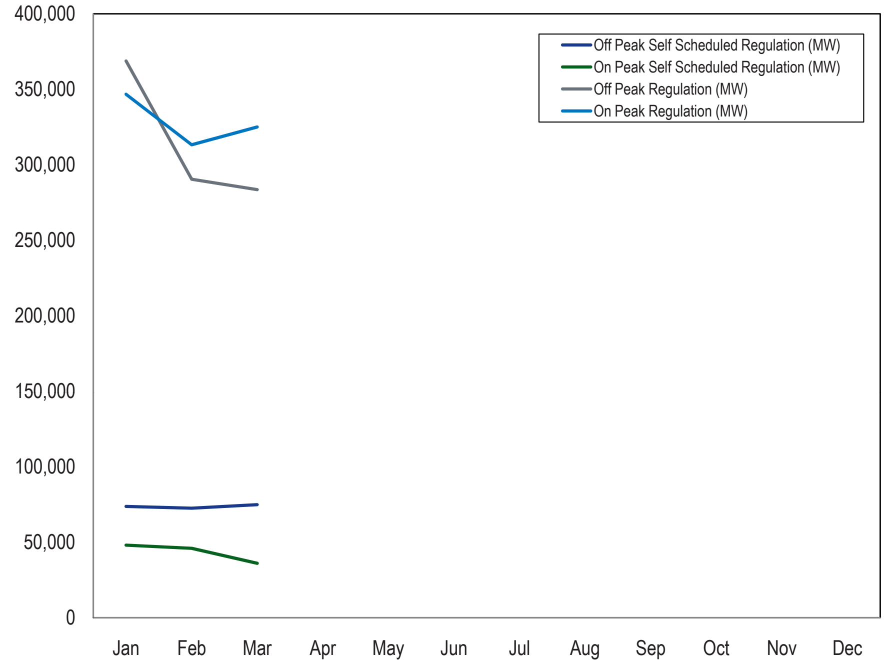


Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March, 2011 (See 2010 SOM, Table 6-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	$576,029	$116,421	$16,670
Feb	$462,394	$114,568	$17,553
Mar	$463,708	$107,791	$28,109

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through March, 2011 (See 2010 SOM, Figure 6-3)

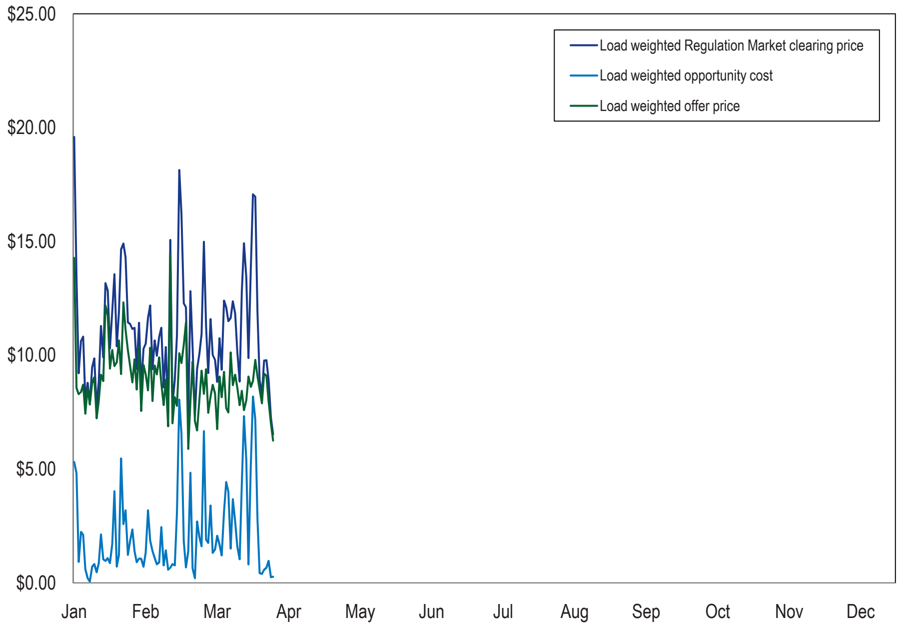


Figure 6-4 Monthly average regulation demand (required) vs. price: January through March, 2011 (See 2010 SOM, Figure 6-4)

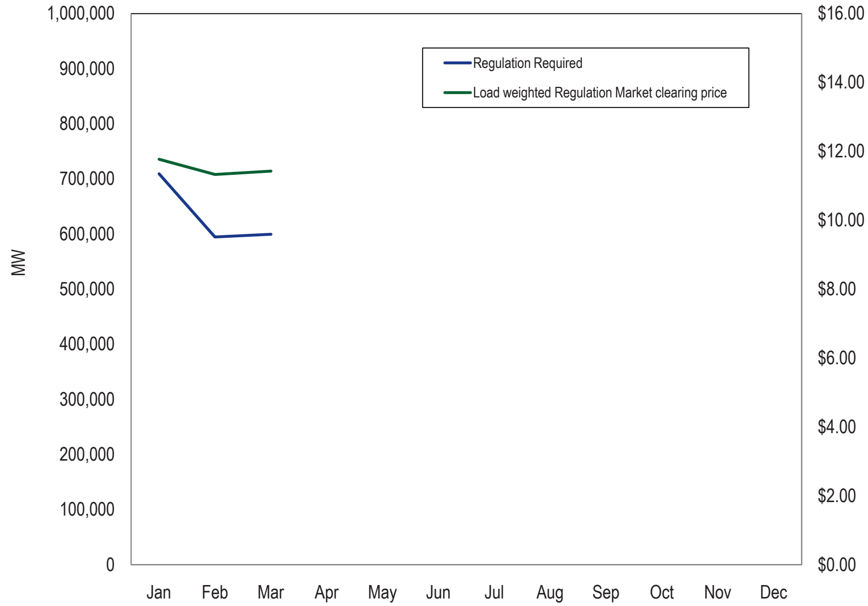


Figure 6-5 Monthly load weighted, average regulation cost and price: January through March, 2011 (See 2010 SOM, Figure 6-5)

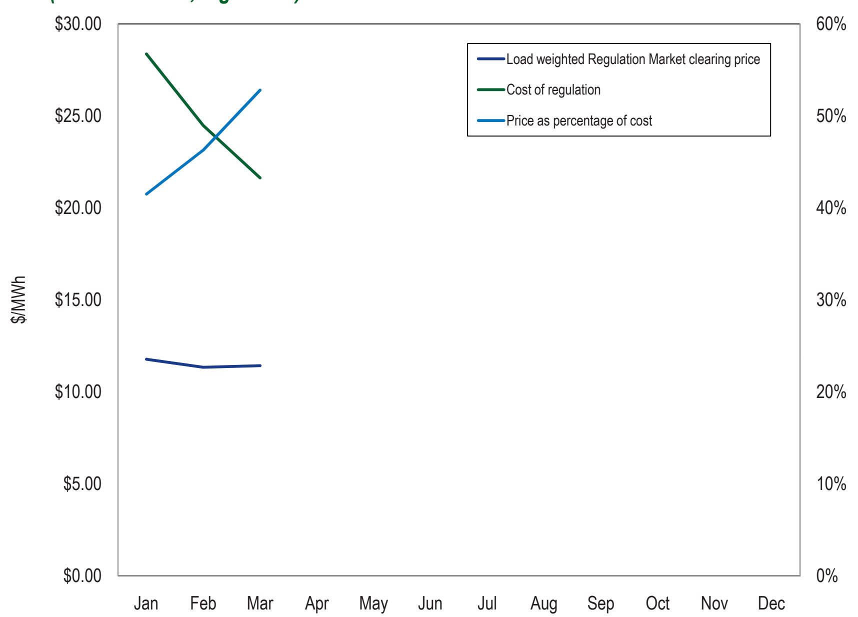


Table 6-11 Total regulation charges: January through March, 2011 (See 2010 SOM, Table 6-11)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.77	$28.37
Feb	594,515	$14,551,995	$11.33	$24.48
Mar	599,608	$12,967,924	$11.42	$21.63

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through March 2011[19] (See 2010 SOM, Table 6-12)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
2006	$32.69	$44.98	73%
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$11.51	$24.83	46%

Analysis of Regulation Market Changes

Table 6-13 Summary of changes to Regulation Market design (See 2010 SOM, Table 6-13)

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

19 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

Increase Offer Margin from $7.50 to $12.00

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through March 2011 (See 2010 SOM, Table 6-14)

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3.5%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3.1%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	3.5%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	1.8%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2.1%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1.3%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1.3%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2.1%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	1.6%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3.3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3.5%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	2.5%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3.5%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0.4%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0.2%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	0.5%
2010	Apr	$17.43	$17.10	$13,124,014	$167,101	1.3%
2010	May	$19.36	$18.83	$18,674,880	$299,170	1.6%
2010	Jun	$19.65	$19.42	$21,783,561	$138,358	0.6%
2010	Jul	$23.47	$23.38	$31,927,050	$60,049	0.2%
2010	Aug	$21.32	$21.22	$27,062,825	$71,696	0.3%
2010	Sep	$19.25	$19.10	$18,341,488	$84,500	0.5%
2010	Oct	$13.53	$13.47	$10,158,529	$27,076	0.3%
2010	Nov	$11.78	$11.70	$11,392,510	$42,183	0.4%
2010	Dec	$14.04	$14.03	$25,225,775	$96,809	0.4%
2011	Jan	$11.77	$11.76	$18,852,265	$45,866	0.2%
2011	Feb	$11.33	$11.31	$13,581,735	$33,442	0.2%
2011	Mar	$11.42	$11.26	$11,908,985	$142,190	1.2%
Total				$530,189,642	$7,629,288	1.4%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through March 2011 (See 2010 SOM, Table 6-15)

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1.0%
2009	Jan	$127,036	$26,614,105	0.5%
2009	Feb	$220,460	$20,972,293	1.1%
2009	Mar	$79,726	$17,618,413	0.5%
2009	Apr	$8,893	$12,171,811	0.1%
2009	May	$182,624	$21,166,797	0.9%
2009	Jun	$274,916	$24,566,721	1.1%
2009	Jul	$191,538	$20,065,104	1.0%
2009	Aug	$267,116	$23,010,216	1.2%
2009	Sep	$252,136	$15,216,790	1.7%
2009	Oct	$169,130	$12,882,665	1.3%
2009	Nov	$166,112	$10,695,843	1.6%
2009	Dec	$104,496	$17,303,919	0.6%
2010	Jan	$64,990	$29,465,392	0.2%
2010	Feb	$64,727	$16,640,892	0.4%
2010	Mar	$109,344	$14,156,600	0.8%
2010	Apr	$134,738	$13,246,951	1.0%
2010	May	$74,352	$18,674,880	0.4%
2010	Jun	$41,065	$21,783,561	0.2%
2010	Jul	$85,961	$31,927,050	0.3%
2010	Aug	$110,610	$27,062,825	0.4%
2010	Sep	$58,587	$18,341,488	0.3%
2010	Oct	$34,911	$10,158,529	0.3%
2010	Nov	$33,676	$11,392,510	0.3%
2010	Dec	$126,074	$25,225,775	0.5%
2011	Jan	$43,498	$18,852,265	0.2%
2011	Feb	$30,394	$13,581,735	0.2%
2011	Mar	$70,768	$11,908,985	0.6%
Total		$3,381,041	$530,312,579	0.6%

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March, 2011 (See 2010 SOM, Figure 6-6)

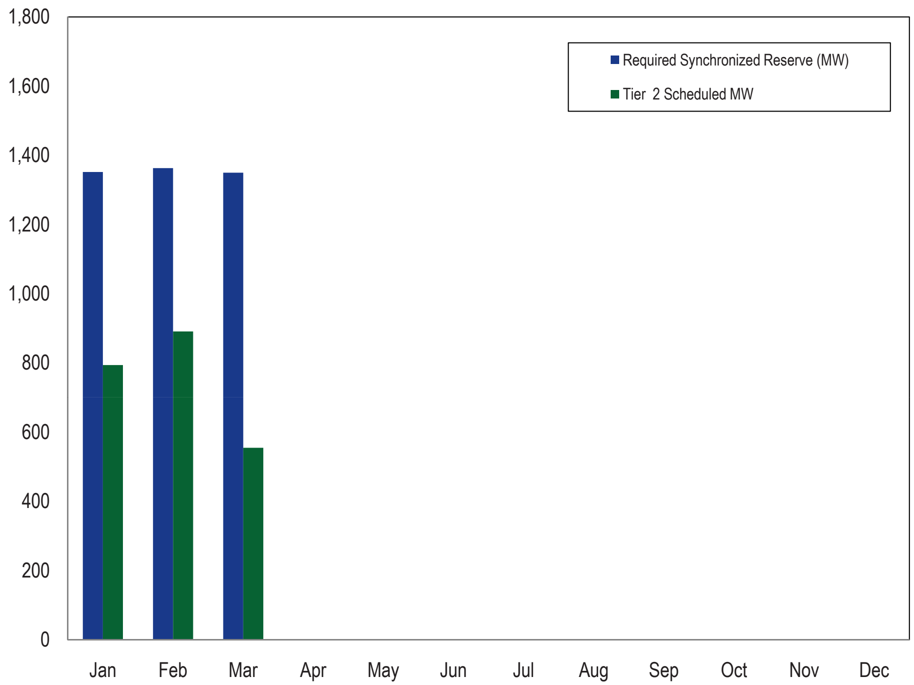


Figure 6-7 Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through March, 2011 (See 2010 SOM, Figure 6-7)

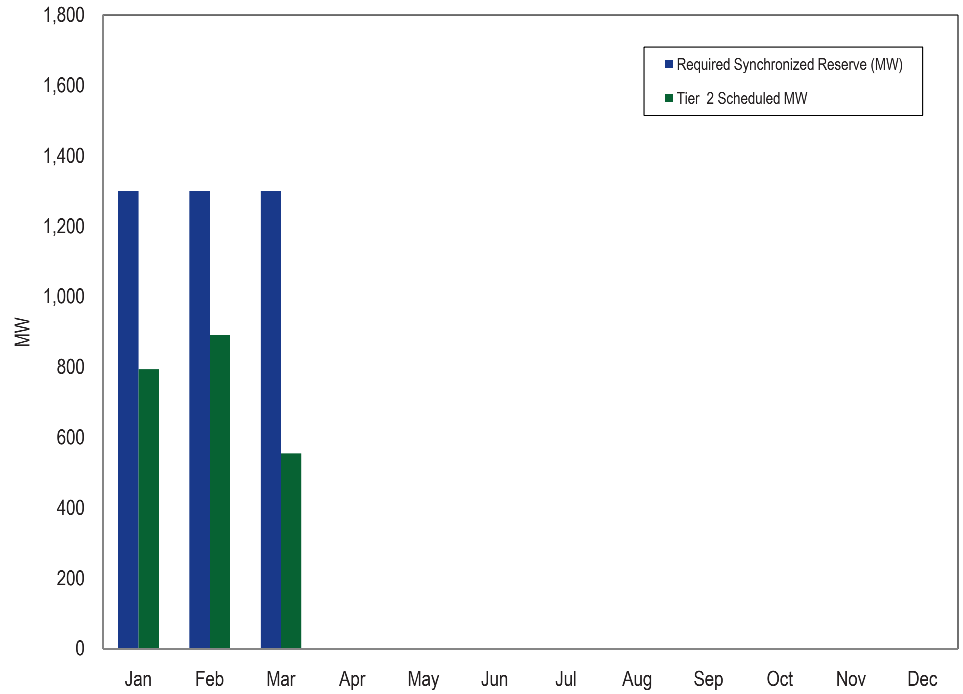
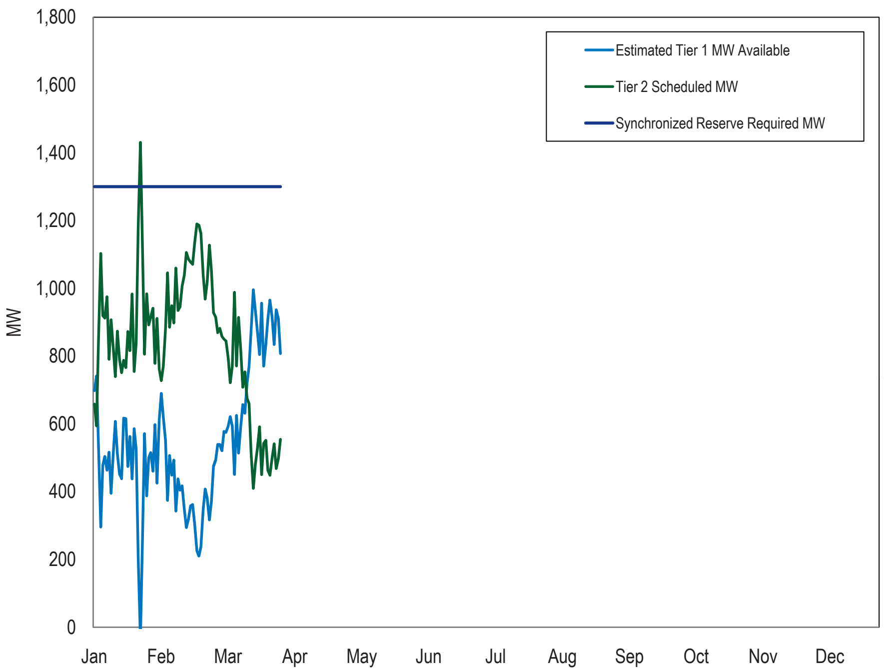


Figure 6-8 Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through March, 2011 (See 2010 SOM, Figure 6-8)



Market Concentration

Table 6-16 Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market cleared market shares: January through March, 2011 (See 2010 SOM, Table 6-16)

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	33%
2	30%
3	16%
4	14%
5	14%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March, 2011 (See 2010 SOM, Figure 6-9)

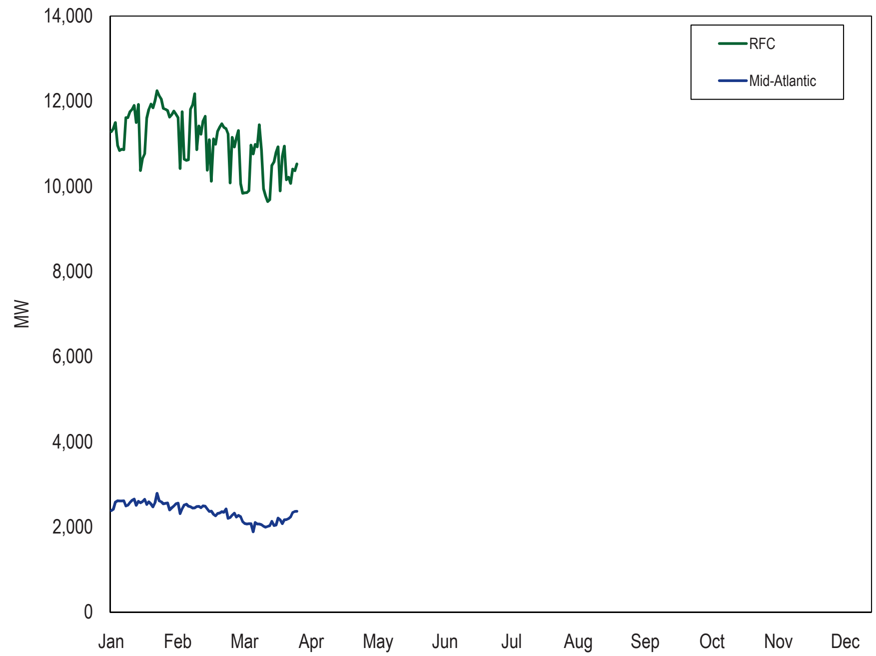


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March, 2011 (See 2010 SOM, Table 6-10)

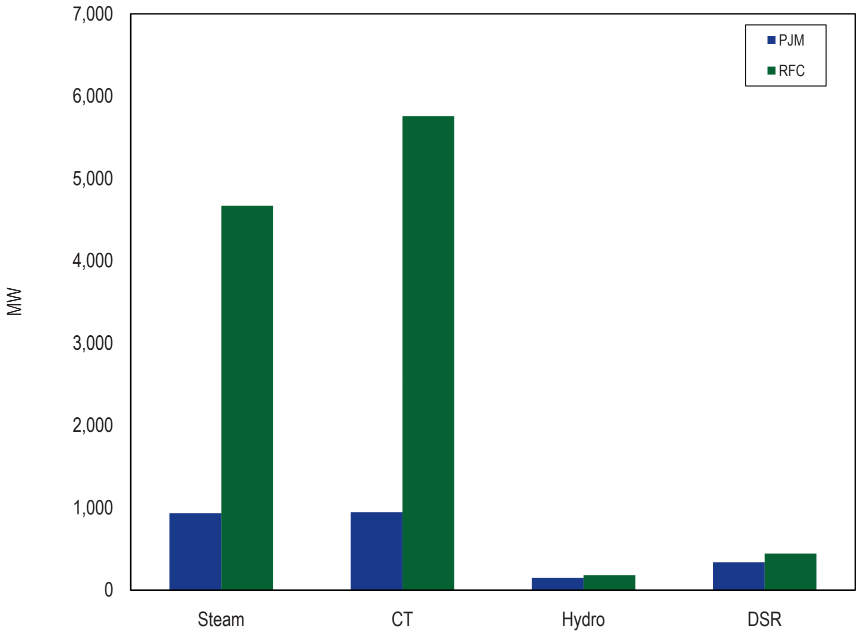
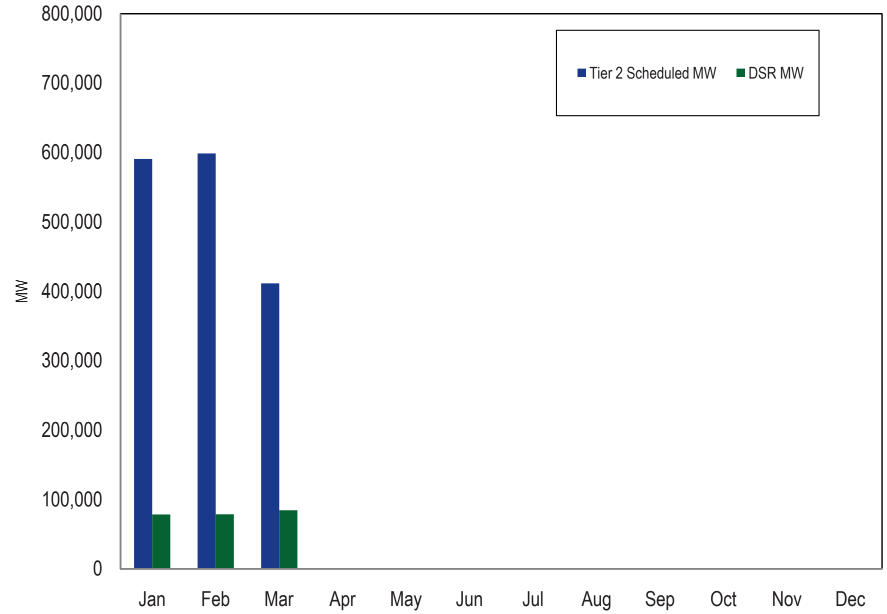


Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through March, 2011 (See 2010 SOM, Figure 6-11)



DSR

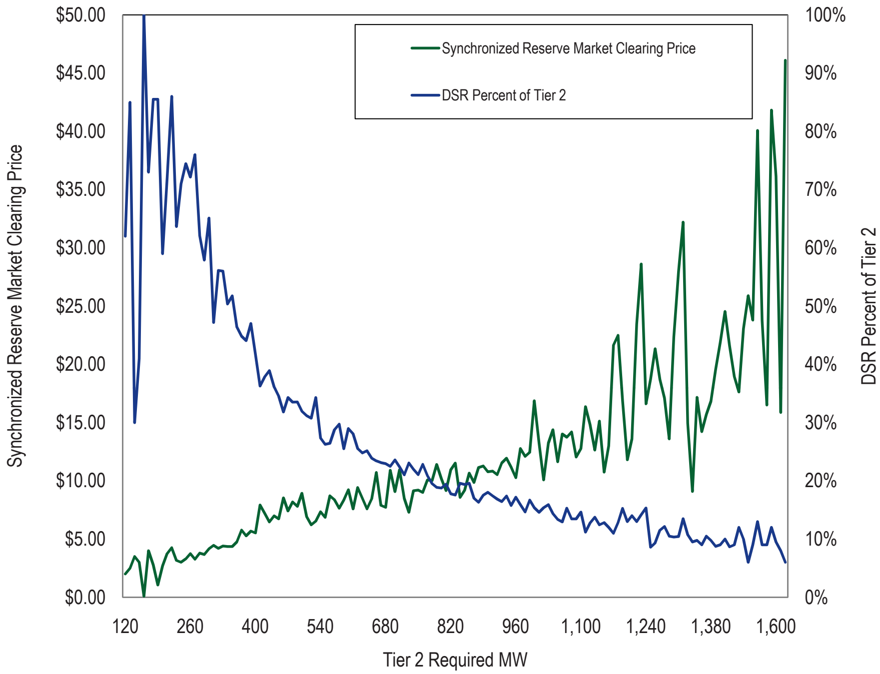
Table 6-17 Average SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through March 2010 and January through March 2011 (See 2010 SOM, Table 6-17)

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.03	6%
2011	Jan	$10.75	$0.10	0%
2011	Feb	$10.91		0%
2011	Mar	$11.33	$2.04	2%

Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through March, 2011 (See 2010 SOM, Figure 6-12)



Price and Cost

Figure 6-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March, 2011 (See 2010 SOM, Figure 6-13)

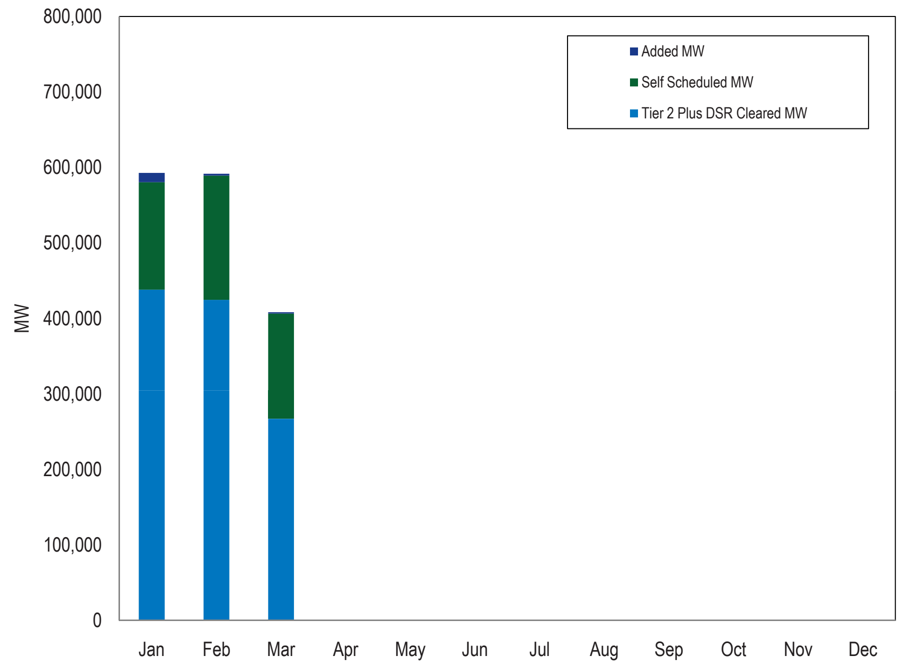


Figure 6-14 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Subzone: January through March, 2011 (See 2010 SOM, Figure 6-14)

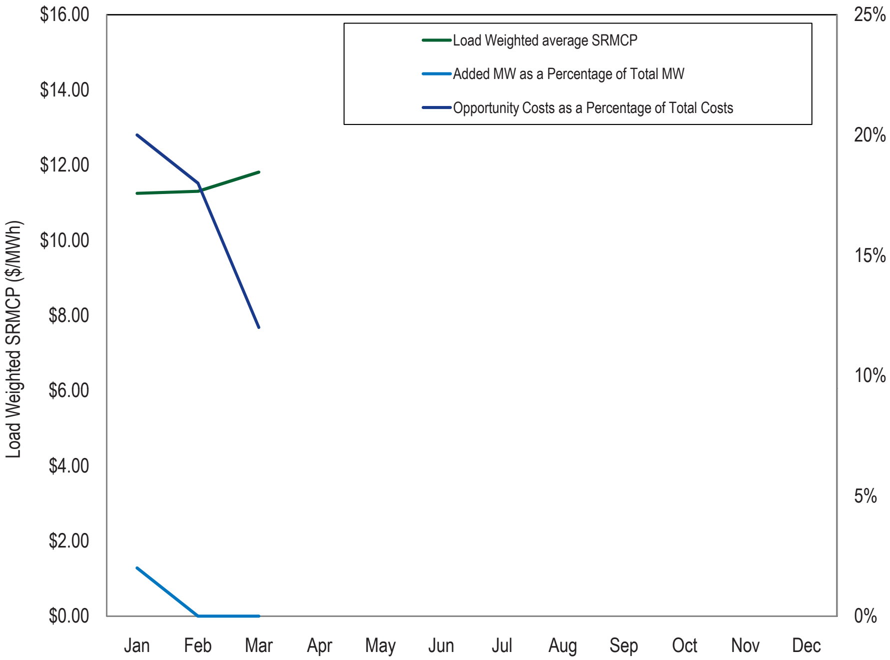


Figure 6-15 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through March, 2011 (See 2010 SOM, Figure 6-15)

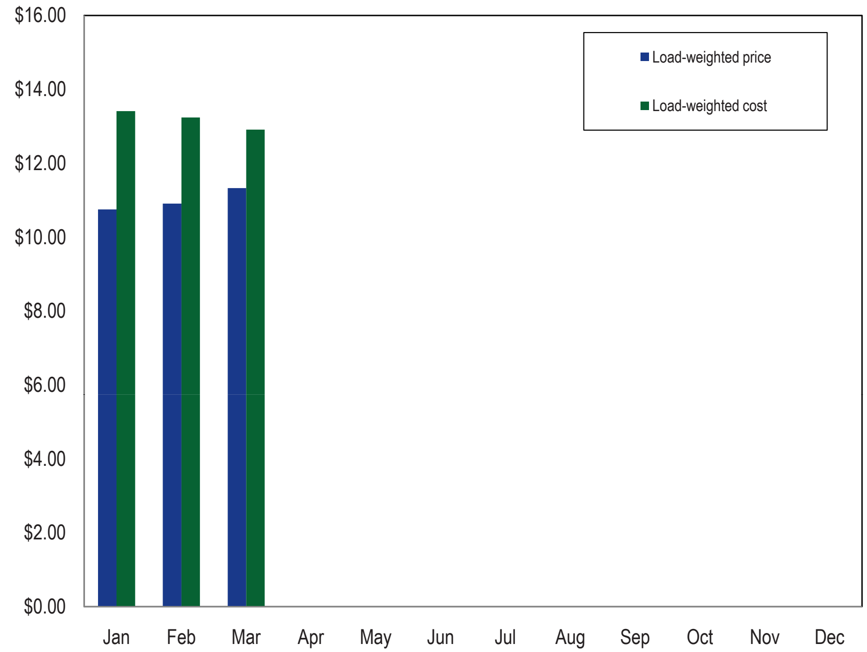


Table 6-18 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through March 2011 (See 2010 SOM, Table 6-18)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010	$10.55	$14.41	73%
2011	$10.96	$13.22	83%

Day Ahead Scheduling Reserve (DASR)

Market Conduct

Table 6-19 Count of units by unit type offering DASR at $900/MW: January through March, 2011 (See 2010 SOM, Table 6-19)

Unit Type	Distinct Units
CT	21
Diesel	2
Nuclear	10
Steam	6
Wind	5

Market Performance

Table 6-20 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March, 2011 (See 2010 SOM, Table 6-20)

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837.00
Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682.00
Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,835.00

Black Start Service

Table 6-21 Black start yearly zonal charges for network transmission use: January through March, 2011 (See 2010 SOM, Table 6-21)

Zone	Network Charges	Black Start Rate
AECO	$97,979	$0.37
AEP	$148,254	$0.07
AP	$36,436	$0.05
BGE	$137,342	$0.22
ComEd	$1,027,440	$0.52
DAY	$35,302	$0.12
DLCO	$8,162	$0.03
DPL	$90,675	$0.25
JCPL	$120,773	$0.21
Met-Ed	$113,979	$0.43
PECO	$219,676	$0.28
PENELEC	$88,994	$0.33
Pepco	$72,465	$0.12
PPL	$35,616	$0.05
PSEG	$591,219	$0.61

SECTION 7 – CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets in the first three months of 2011.

Highlights

- 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.

- 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.

- 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.

- 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).

- 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.

  On February 28, 2011, PJM announced that the Board decided to hold the 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 Potomac – Appalachian Transmission Highline (PATH) project.

  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.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

2 See the *2010 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

Recommendations

- 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.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $15.8 million or 4.6 percent, from $345.1 million in the first three months of 2010 to $360.9 million in the first three months of 2011. Day-ahead congestion costs increased by $14.9 million or 3.8 percent, from $391.9 million in the first three months of 2010 to $406.9 million in the first three months of 2011. Balancing congestion costs increased by $0.8 million or 1.8 percent from -$46.9 million in the first three months of 2010 to -$46.0 million in the first three months of 2011. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in the first three months of 2011, which is similar to the four percent share for calendar year 2010, but lower than the share of total billings from 2003 through 2008. Total PJM billings in the first three months of 2011 were $9.584 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first three months of 2011, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in the first three months of 2011 ranged from $45.0 million in March to $241.8 million in January.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the 5004/5005 interface, the Bedington – Black Oak interface, and the Belmont and Susquehanna transformers (Table 7-13). The AP South interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2011.[3] Day-ahead congestion frequency increased by 23.3 percent from 20,381 congestion event hours in the first three months of 2010 to 25,138 congestion event hours in the first three months of 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces. While congestion frequency increased on lines, transformers and reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO).

  Real-time congestion frequency increased by 17.6 percent from 3,772 congestion event hours in the first three months of 2010 to 4,435 congestion event hours in the first three months of 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and the Midwest ISO.

  The AP South Interface was the largest contributor to congestion costs in the first three months of 2011. With $133.2 million in total congestion costs, it accounted for 38 percent of the total PJM congestion costs in the first three months of 2011. The top five constraints in terms of congestion costs together contributed $255.1 million, or 74 percent, of the total PJM congestion costs in the first three months of 2011. The top five constraints were the AP South interface, the 5004/5005 interface, the Bedington – Black Oak interface, the Belmont transformer and the Susquehanna transformer. Facilities were constrained in the Day-Ahead market more frequently than in the real-time market. During the first three months of 2011, among the hours for which a facility is constrained in the day-ahead market, the facilities were also constrained in the real-time market for only 7.9 percent of those hours.

- **Zonal Congestion.** In the first three months of 2011, the AP Control Zone experienced the highest congestion costs of the control zones in PJM with $66.7 million. The AP South interface, the Belmont transformer,

3 In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

the 5004/5005 interface, the Bedington – Black Oak interface, and the Wylie Ridge transformer contributed $63.2 million, or 95 percent of the total AP Control Zone congestion costs (Table 7-55). The AEP Control Zone recorded the second highest congestion cost in PJM in the first three months of 2011. The $58.7 million in congestion costs in the AEP Control Zone is not much different from $59.3 million in congestion costs for the zone in the first three months of 2010. The AP South interface contributed $18.3 million, or 31 percent of the total AEP Control Zone congestion cost in the first three months of 2011. Increases in day-ahead congestion frequency and congestion costs from the AP South interface and the Belmont transformer also contributed to the increase in congestion cost in the AEP Control Zone in the first three months of 2011 compared to that of 2010. The AP South interface contributed $18.3 million to the AEP Control Zone congestion costs and the Belmont transformer contributed $10.1 million to the AEP Control Zone congestion costs.

- **Ownership.** In the PJM market, both physical and financial participants use virtual supply (increments) and virtual demand (decrements). A participant is classified as a financial entity if the entity primarily takes physical positions (fixed demand and generation) in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are grouped as a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company. In the first three months of 2011, financial companies as a group were net recipients of congestion charges, whereas physical companies were net payers of congestion charges. In the first three months of 2011, the financial companies collected $8.5 million, a decrease of $28.2 million or 77 percent compared to the first three months of 2010. In the first three months of 2011, the physical companies paid $369.4 million toward congestion charges, a decrease of 12.4 million or 3 percent compared to the first three months of 2010.

Key Backbone Facilities

PJM baseline projects are implemented to resolve reliability criteria violations. 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. The current backbone projects are: Mount Storm – Doubs; Carson – Suffolk; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); Susquehanna – Roseland; and the Trans Allegheny Line (TrAIL). The total planned costs for all of these projects are $6,048.4 million.

On February 28, 2011, PJM issued a press release stating:

> As part of its 2011 RTEP, and in response to a request by a Virginia Hearing Examiner, PJM is conducting a series of analyses using the most current economic forecasts and Demand Response commitments, as well as potential new generation resources. Preliminary analysis reveals the expected reliability violations that necessitated PATH have moved several years into the future.
>
> Based on these latest results, the Board has decided to hold the PATH project in abeyance in its 2011 RTEP. The Board further directs the sponsoring Transmission Owners to suspend current development efforts on the PATH project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the potential need for PATH as part of its continuing RTEP process. This action, however, does not, at this time, constitute a directive by PJM to the sponsoring Transmission Owners to cancel or abandon the PATH project.[4]

Following the PJM press release on February 28, 2011, American Electric Power and FirstEnergy Corp. issued a press release stating that “their affiliates will file to withdraw their applications for state regulatory approval of the Potomac-Appalachian Transmission Highline (PATH) project following an announcement by regional grid operator PJM Interconnection that the project has been suspended.”[5]

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical

4 See “Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers”. http://www.pjm.com/~/media/documents/reports/20110228-bom-statement-planning-for-transmission.ashx.

5 See “PATH Seeks to Withdraw Applications for Electric Transmission Project”. http://www.pathtransmission.com.

distribution of load. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in 2010. Total PJM billings in the first three months of 2011 were $9,584 million. Total congestion costs increased by $15.8 million or 4.6 percent, from $345.1 million in the first three months of 2010 to $360.9 million in the first three months of 2011. Day-ahead congestion costs increased by $14.9 million or 3.8 percent, from $391.9 million in the first three months of 2010 to $460.9 million in the first three months of 2011. Balancing congestion costs increased by $0.8 million or 1.8 percent, from -$46.9 million in the first three months of 2010 to -$46.0 million in the first three month of 2011. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 20,381 congestion event hours in the first three months of 2010 to 25,138 congestion event hours or 23.3 percent in the first three months of 2011. Real-time congestion frequency increased from 3,772 congestion event hours in the first three months of 2010 to 4,435 congestion event hours or 17.6 percent in the first three months of 2011

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period.[6] During the first ten months (June 2010 through March 2011) of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 97.4 percent of the congestion costs within PJM. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 87.9 percent of the target allocation level for the first ten months of the 2010 to 2011 planning period.[7] Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs and FTRs as a hedge. The value of ARRs and FTRs was 4.0 percent of total real-time energy charges to load for the first three months of 2011.[8]

One constraint accounted for 38 percent of total congestion costs in the first three months of 2010 and the top five constraints accounted for 74 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in the first three months of 2011.

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2011 (See 2010 SOM, Table 7-1)

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010	$1,428	99%	$34,770	4%
2011 (Jan - Mar)	$361		$9,584	4%
Total	$9,591		$194,941	5%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through March, 2010 and 2011 (See 2010 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2010 (Jan - Mar)	$79.8	($281.6)	($16.3)	$345.1
2011 (Jan - Mar)	$198.6	($198.9)	($36.7)	$360.9

6 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-33, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."

7 See the *2011 Quarterly State of the Market Report for PJM: January through March* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-10, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 through March 31, 2011"

8 See the *2011 Quarterly State of the Market Report for PJM: January through March* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-19, "ARRs and FTRs as a hedge against energy charges by control zone: January through March 2011"

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2010 to 2011 (See 2010 SOM, Table 7-3)

	2010	2011	Change	Percent Change
Jan	$218.5	$241.8	$23.3	10.7%
Feb	$106.4	$74.0	($32.4)	(30.4%)
Mar	$20.4	$45.0	$24.6	120.8%
Apr	$42.6			
May	$68.5			
Jun	$188.5			
Jul	$268.9			
Aug	$105.1			
Sep	$119.9			
Oct	$50.3			
Nov	$52.0			
Dec	$187.1			
Total	$1,428.1	$360.9		

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through March 2010 and 2011 (See 2010 SOM, Table 7-4)

	2010 (Jan - Mar)		2011 (Jan - Mar)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$2.12	$1.73	$5.05	$4.81
AEP	($3.50)	($2.98)	($4.66)	($4.46)
AP	($1.06)	($0.33)	($0.50)	($0.31)
BGE	$4.65	$4.06	$4.66	$4.19
ComEd	($6.22)	($6.15)	($7.81)	($7.15)
DAY	($4.78)	($4.15)	($5.53)	($5.16)
DLCO	($4.20)	($2.67)	($7.25)	($6.76)
DPL	$2.36	$2.18	$4.64	$3.53
Dominion	$6.57	$4.52	$4.12	$3.36
JCPL	$1.77	$1.34	$5.07	$4.48
Met-Ed	$2.34	$1.71	$4.21	$3.46
PECO	$2.20	$1.72	$4.89	$3.95
PENELEC	($1.99)	($1.93)	($0.86)	($0.72)
PPL	$2.19	$1.47	$5.43	$4.68
PSEG	$2.80	$3.31	$6.19	$5.33
Pepco	$6.44	$4.86	$5.59	$4.64
RECO	$1.70	$0.44	$2.89	($0.16)

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through March 2011 (See 2010 SOM, Table 7-5)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$2.0	($16.0)	($0.9)	$17.0	$4.8	$3.6	($21.1)	($19.9)	($2.9)	2,716	1,108
Interface	$79.6	($173.1)	($5.6)	$247.1	$14.2	$14.4	$3.1	$2.9	$250.0	2,957	877
Line	$34.2	($33.6)	$6.0	$73.8	$1.7	$8.6	($18.3)	($25.2)	$48.6	13,761	1,510
Other	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	2
Transformer	$59.5	($4.0)	$2.1	$65.7	$1.0	$1.0	($4.0)	($4.0)	$61.6	5,704	938
Unclassified	$1.2	$0.0	$2.2	$3.3	$0.4	$0.0	($0.2)	$0.1	$3.5	NA	NA
Total	$176.4	($226.6)	$3.8	$406.9	$22.2	$27.7	($40.5)	($46.0)	$360.9	25,138	4,435

Table 7-6 Congestion summary (By facility type): January through March 2010 (See 2011 SOM, Table 7-6)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($1.1)	($11.5)	$3.0	$13.4	($0.5)	$1.2	($9.2)	($10.9)	$2.5	1,773	260
Interface	$47.2	($238.6)	($1.9)	$283.9	$6.4	$3.6	$1.7	$4.5	$288.4	3,096	1,151
Line	$29.4	($37.4)	$10.1	$76.9	($12.2)	$7.3	($21.2)	($40.6)	$36.3	13,053	2,046
Transformer	$9.8	($5.6)	$1.1	$16.4	$0.4	($0.4)	($0.6)	$0.2	$16.6	2,459	315
Unclassified	$0.5	($0.1)	$0.6	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	NA	NA
Total	$85.8	($293.3)	$12.9	$391.9	($6.0)	$11.7	($29.2)	($46.9)	$345.1	20,381	3,772

Table 7-7 Congestion Event Hours (Day Ahead against Real Time): January through March 2010 and 2011 (See 2010 SOM, Table 7-7)

	Congestion Event Hours					
	2011 (Jan - Mar)			2010 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	2,716	456	16.8%	1,773	105	5.9%
Interface	2,957	683	23.1%	3,096	829	26.8%
Line	13,761	391	2.8%	13,053	862	6.6%
Other	0	0	0.0%	0	0	0.0%
Transformer	5,704	484	8.5%	2,459	65	2.6%
Total	19,434	1,530	7.9%	17,922	1,796	10.0%

Table 7-8 Congestion Event Hours (Real Time against Day Ahead): January through March 2010 and 2011 (See 2010 SOM, Table 7-8)

	Congestion Event Hours					
	2011 (Jan - Mar)			2010 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,108	462	41.7%	260	106	40.8%
Interface	877	682	77.8%	1,151	829	72.0%
Line	1,510	386	25.6%	2,046	802	39.2%
Other	2	0	0.0%	0	0	0.0%
Transformer	938	484	51.6%	315	63	20.0%
Total	3,497	1,530	43.8%	3,457	1,737	50.2%

Table 7-9 Congestion summary (By facility voltage): January through March 2011 (See 2010 SOM, Table 7-9)

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.1	($0.8)	$0.2	$1.1	$1.7	$1.0	($2.2)	($1.6)	($0.5)	8	20
500	$83.2	($175.0)	($5.4)	$252.7	$16.3	$15.2	$2.5	$3.7	$256.5	3,175	1,075
345	$37.0	($7.9)	$4.9	$49.8	$5.4	$7.4	($27.6)	($29.6)	$20.2	6,946	1,410
230	$14.9	($23.6)	($0.3)	$38.3	$1.6	$1.3	($0.3)	$0.0	$38.3	4,355	464
138	$35.2	($18.3)	$2.1	$55.6	($2.3)	$1.5	($12.4)	($16.2)	$39.4	7,861	1,284
115	$1.4	($0.7)	$0.2	$2.3	($0.2)	$0.4	($0.1)	($0.7)	$1.6	1,061	82
69	$3.4	($0.3)	($0.0)	$3.6	($0.7)	$0.8	($0.2)	($1.8)	$1.9	1,690	98
34	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	2
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	42	0
Unclassified	$1.2	$0.0	$2.2	$3.3	$0.4	$0.0	($0.2)	$0.1	$3.5	NA	NA
Total	$176.4	($226.6)	$3.8	$406.9	$22.2	$27.7	($40.5)	($46.0)	$360.9	25,138	4,435

Table 7-10 Congestion summary (By facility voltage): January through March 2010 (See 2010 SOM, Table 7-10)

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.5	($1.7)	$0.5	$2.7	($1.1)	($0.1)	($3.2)	($4.2)	($1.5)	56	74
500	$50.9	($243.7)	($1.3)	$293.3	$5.6	$1.8	$0.6	$4.4	$297.7	3,440	1,401
345	$4.0	($18.5)	$3.8	$26.3	($3.4)	$2.4	($14.7)	($20.6)	$5.7	2,058	735
230	$9.2	($6.9)	$5.8	$21.9	($5.9)	$7.0	($9.4)	($22.3)	($0.5)	4,992	526
138	$15.1	($24.2)	$3.5	$42.8	($1.4)	($0.0)	($2.3)	($3.7)	$39.0	7,536	918
115	$5.1	$1.9	$0.1	$3.4	$0.2	$0.6	($0.1)	($0.4)	$3.0	589	111
69	$0.3	($0.1)	($0.0)	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	1,437	7
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
12	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	255	0
Unclassified	$0.5	($0.1)	$0.6	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	NA	NA
Total	$85.8	($293.3)	$12.9	$391.9	($6.0)	$11.7	($29.2)	($46.9)	$345.1	20,381	3,772

Constraint Duration

Table 7-11 Top 25 constraints with frequent occurrence: January through March 2010 to 2011 (See 2010 SOM, Table 7-11)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	1,730	1,730	0	203	203	0%	20%	20%	0%	2%	2%
2	Crete - St Johns Tap	Flowgate	129	1,456	1,327	1	398	397	1%	17%	15%	0%	5%	5%
3	AP South	Interface	1,255	1,172	(83)	735	513	(222)	14%	13%	(1%)	8%	6%	(3%)
4	Belmont	Transformer	73	1,543	1,470	0	105	105	1%	18%	17%	0%	1%	1%
5	Wylie Ridge	Transformer	11	1,235	1,224	2	329	327	0%	14%	14%	0%	4%	4%
6	Wolfcreek	Transformer	0	729	729	0	94	94	0%	8%	8%	0%	1%	1%
7	Emilie - Falls	Line	0	789	789	0	0	0	0%	9%	9%	0%	0%	0%
8	5004/5005 Interface	Interface	806	513	(293)	294	241	(53)	9%	6%	(3%)	3%	3%	(1%)
9	Cedar Grove - Roseland	Line	89	713	624	0	26	26	1%	8%	7%	0%	0%	0%
10	Pleasant Prairie - Zion	Flowgate	556	593	37	110	140	30	6%	7%	0%	1%	2%	0%
11	Bedington - Black Oak	Interface	519	576	57	9	0	(9)	6%	7%	1%	0%	0%	(0%)
12	Linden - VFT	Line	2	538	536	0	0	0	0%	6%	6%	0%	0%	0%
13	Carnegie - Tidd	Line	0	323	323	0	202	202	0%	4%	4%	0%	2%	2%
14	Pinehill - Stratford	Line	293	513	220	0	0	0	3%	6%	3%	0%	0%	0%
15	Electric Jct - Nelson	Line	0	447	447	0	39	39	0%	5%	5%	0%	0%	0%
16	Burlington - Croydon	Line	512	451	(61)	13	0	(13)	6%	5%	(1%)	0%	0%	(0%)
17	Butler - Karns City	Line	0	369	369	0	44	44	0%	4%	4%	0%	1%	1%
18	Bridgewater - Middlesex	Line	25	377	352	5	19	14	0%	4%	4%	0%	0%	0%
19	Carnegie - Tidd	Line	0	388	388	0	0	0	0%	4%	4%	0%	0%	0%
20	AEP-DOM	Interface	452	293	(159)	76	88	12	5%	3%	(2%)	1%	1%	0%
21	Cox's Corner - Marlton	Line	0	355	355	0	0	0	0%	4%	4%	0%	0%	0%
22	Fairview	Transformer	0	353	353	0	0	0	0%	4%	4%	0%	0%	0%
23	Nelson - Cordova	Line	0	321	321	2	20	18	0%	4%	4%	0%	0%	0%
24	Cherry Valley	Transformer	0	325	325	0	10	10	0%	4%	4%	0%	0%	0%
25	Cloverdale - Lexington	Line	154	173	19	97	155	58	2%	2%	0%	1%	2%	1%

Table 7-12 Top 25 constraints with largest year-to-year change in occurrence: January through March 2010 to 2011 (See 2010 SOM, Table 7-12)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2010	2011	Change	2010	2011	Change	2010	2011	Change	2010	2011	Change
1	South Mahwah - Waldwick	Line	0	1,730	1,730	0	203	203	0%	20%	20%	0%	2%	2%
2	Athenia - Saddlebrook	Line	1,779	180	(1,599)	273	0	(273)	20%	2%	(18%)	3%	0%	(3%)
3	Crete - St Johns Tap	Flowgate	129	1,456	1,327	1	398	397	1%	17%	15%	0%	5%	5%
4	Belmont	Transformer	73	1,543	1,470	0	105	105	1%	18%	17%	0%	1%	1%
5	Wylie Ridge	Transformer	11	1,235	1,224	2	329	327	0%	14%	14%	0%	4%	4%
6	Waterman - West Dekalb	Line	812	0	(812)	159	0	(159)	9%	0%	(9%)	2%	0%	(2%)
7	East Frankfort - Crete	Line	835	288	(547)	419	1	(418)	10%	3%	(6%)	5%	0%	(5%)
8	Wolfcreek	Transformer	0	729	729	0	94	94	0%	8%	8%	0%	1%	1%
9	Emilie - Falls	Line	0	789	789	0	0	0	0%	9%	9%	0%	0%	0%
10	Cedar Grove - Roseland	Line	89	713	624	0	26	26	1%	8%	7%	0%	0%	0%
11	Tiltonsville - Windsor	Line	697	223	(474)	140	45	(95)	8%	3%	(5%)	2%	1%	(1%)
12	Linden - VFT	Line	2	538	536	0	0	0	0%	6%	6%	0%	0%	0%
13	Carnegie - Tidd	Line	0	323	323	0	202	202	0%	4%	4%	0%	2%	2%
14	Rising	Flowgate	582	48	(534)	32	54	22	7%	1%	(6%)	0%	1%	0%
15	Electric Jct - Nelson	Line	0	447	447	0	39	39	0%	5%	5%	0%	0%	0%
16	Bayonne - PVSC	Line	507	34	(473)	0	0	0	6%	0%	(5%)	0%	0%	0%
17	Hawthorn - Waldwick	Line	454	30	(424)	36	0	(36)	5%	0%	(5%)	0%	0%	(0%)
18	Butler - Karns City	Line	0	369	369	0	44	44	0%	4%	4%	0%	1%	1%
19	Carnegie - Tidd	Line	0	388	388	0	0	0	0%	4%	4%	0%	0%	0%
20	Bridgewater - Middlesex	Line	25	377	352	5	19	14	0%	4%	4%	0%	0%	0%
21	Cox's Corner - Marlton	Line	0	355	355	0	0	0	0%	4%	4%	0%	0%	0%
22	Fairview	Transformer	0	353	353	0	0	0	0%	4%	4%	0%	0%	0%
23	5004/5005 Interface	Interface	806	513	(293)	294	241	(53)	9%	6%	(3%)	3%	3%	(1%)
24	Sammis - Wylie Ridge	Line	305	1	(304)	37	0	(37)	3%	0%	(3%)	0%	0%	(0%)
25	Nelson - Cordova	Line	0	321	321	2	20	18	0%	4%	4%	0%	0%	0%

Constraint Costs

Table 7-13 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 2011 (See 2010 SOM, Table 7-13)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011 (Jan - Mar)
1	AP South	Interface	500	$3.2	($129.5)	$0.5	$133.2	$7.8	$7.8	($0.7)	($0.7)	$132.5	38%
2	5004/5005 Interface	Interface	500	$50.5	($13.2)	($4.4)	$59.3	$5.6	$5.1	$3.6	$4.2	$63.4	18%
3	Bedington - Black Oak	Interface	500	$5.3	($19.2)	($2.0)	$22.5	$0.0	$0.0	$0.0	$0.0	$22.5	7%
4	Belmont	Transformer	AP	$13.3	($13.0)	($2.2)	$24.1	($1.5)	($0.4)	($0.7)	($1.8)	$22.3	6%
5	Susquehanna	Transformer	PPL	$6.1	($8.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	4%
6	AEP-DOM	Interface	500	$1.5	($11.8)	$0.8	$14.0	$0.6	$0.3	($0.1)	$0.2	$14.2	4%
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.5	($12.5)	($4.0)	$10.0	$3.7	$1.7	($0.8)	$1.2	$11.2	3%
8	West	Interface	500	$13.2	$3.4	($0.1)	$9.7	$0.2	$0.0	$0.1	$0.3	$9.9	3%
9	Wylie Ridge	Transformer	AP	$29.6	$21.2	$1.6	$10.0	$1.5	$0.6	($2.2)	($1.3)	$8.8	3%
10	East	Interface	500	$4.5	($3.1)	($0.2)	$7.5	$0.1	$1.2	$0.1	($1.0)	$6.5	2%
11	Lakeview - Pleasant Prairie	Flowgate	Midwest ISO	($0.0)	($0.1)	$0.2	$0.3	($0.2)	$0.0	($4.2)	($4.4)	($4.1)	(1%)
12	Cloverdale - Lexington	Line	AEP	$1.5	($1.3)	$0.1	$3.0	$2.2	$0.7	($0.4)	$1.0	$4.0	1%
13	Bridgewater - Middlesex	Line	PSEG	$2.7	($1.4)	$0.1	$4.3	$0.1	$0.2	($0.3)	($0.4)	$3.9	1%
14	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($0.1)	($0.8)	$1.7	$2.5	($0.1)	($0.2)	($6.2)	($6.2)	($3.7)	(1%)
15	Butler - Karns City	Line	AP	$6.1	$2.5	($0.1)	$3.4	($0.1)	($0.3)	($0.0)	$0.2	$3.5	1%
16	Cedar Grove - Roseland	Line	PSEG	($1.0)	($4.5)	($0.9)	$2.6	$0.5	$0.5	$0.8	$0.7	$3.3	1%
17	Unclassified	Unclassified	Unclassified	$1.2	$0.0	$2.2	$3.3	$0.0	$0.1	($0.0)	($0.1)	$3.3	1%
18	Electric Jct - Nelson	Line	ComEd	($0.1)	($5.1)	$1.4	$6.4	($0.1)	$0.2	($2.8)	($3.1)	$3.2	1%
19	Plymouth Meeting - Whitpain	Line	PECO	$1.0	($1.9)	$0.0	$2.9	$0.1	$0.0	($0.1)	($0.0)	$2.9	1%
20	Wolfcreek	Transformer	AEP	$4.4	$1.5	($0.3)	$2.5	($0.1)	($0.2)	($0.1)	($0.0)	$2.5	1%
21	Bristers - Ox	Line	Dominion	$2.0	($0.5)	$0.0	$2.6	($0.0)	$0.0	($0.1)	($0.1)	$2.4	1%
22	Collier - Elwyn	Line	DLCO	$1.1	($0.9)	$0.1	$2.1	$0.1	($0.1)	($0.0)	$0.1	$2.2	1%
23	Rising	Flowgate	Midwest ISO	$0.0	($0.5)	$0.1	$0.7	$0.0	$0.5	($2.3)	($2.8)	($2.1)	(1%)
24	Limerick	Transformer	PECO	$1.3	($0.8)	($0.1)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	1%
25	Cherry Valley	Transformer	ComEd	$0.6	($1.2)	$0.3	$2.2	$0.0	$0.1	($0.1)	($0.2)	$2.0	1%

Table 7-14 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 2010 (See 2010 SOM, Table 7-14)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010 (Jan - Mar)
1	AP South	Interface	500	$7.1	($162.6)	($1.1)	$168.5	$4.4	$3.9	$1.2	$1.7	$170.2	55%
2	AEP-DOM	Interface	500	$9.4	($37.8)	$0.9	$48.1	$0.2	($1.2)	$0.1	$1.6	$49.6	16%
3	5004/5005 Interface	Interface	500	$24.1	($19.0)	($0.8)	$42.2	$1.0	$1.0	$0.2	$0.2	$42.5	14%
4	Bedington - Black Oak	Interface	500	$4.1	($19.1)	($0.8)	$22.4	$0.4	($0.5)	$0.1	$0.9	$23.3	8%
5	East Frankfort - Crete	Line	ComEd	$3.5	($11.6)	$1.7	$16.9	($2.5)	$0.8	($4.2)	($7.4)	$9.5	3%
6	Crescent	Transformer	DLCO	$2.8	($2.1)	$0.2	$5.1	$0.0	($0.6)	($0.2)	$0.3	$5.4	2%
7	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($2.4)	($5.9)	$1.5	$5.1	($0.5)	$1.0	($8.6)	($10.2)	($5.1)	(2%)
8	Mount Storm - Pruntytown	Line	AP	$0.6	($3.5)	$0.1	$4.1	($0.3)	($0.8)	$0.1	$0.6	$4.7	2%
9	Athenia - Saddlebrook	Line	PSEG	$3.6	($2.4)	$5.6	$11.6	($6.7)	$4.4	($5.0)	($16.0)	($4.4)	(1%)
10	Rising	Flowgate	Midwest ISO	$0.3	($3.4)	$0.4	$4.2	($0.0)	($0.0)	($0.0)	($0.0)	$4.1	1%
11	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.6)	$0.9	($2.5)	($4.0)	($4.0)	(1%)
12	Baker - Broadford	Line	AEP	($0.0)	($0.3)	$0.0	$0.4	($1.1)	($0.1)	($3.2)	($4.2)	($3.8)	(1%)
13	Kanawha River	Transformer	AEP	$1.3	($1.6)	$0.2	$3.1	$0.0	($0.1)	($0.0)	$0.0	$3.2	1%
14	Tiltonsville - Windsor	Line	AP	$3.3	($0.2)	($0.0)	$3.5	($0.6)	$0.2	$0.3	($0.5)	$3.0	1%
15	West	Interface	500	$2.5	($0.2)	$0.0	$2.7	$0.3	$0.4	$0.2	$0.1	$2.8	1%
16	Culloden - Wyoming	Line	AEP	$0.5	($1.4)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1%
17	Kanawha - Kincaid	Line	AEP	$1.4	($0.8)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1%
18	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	$0.3	($1.5)	($2.0)	($2.2)	(1%)
19	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.8	($1.3)	($2.2)	($2.2)	(1%)
20	Cloverdale - Lexington	Line	AEP	$1.5	($0.6)	$0.2	$2.4	($0.2)	($0.5)	($0.5)	($0.2)	$2.1	1%
21	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	($1.1)	$0.4	$2.1	($0.0)	($0.0)	($0.0)	($0.0)	$2.1	1%
22	Waterman - West Dekalb	Line	ComEd	($1.0)	($2.9)	$0.3	$2.2	$0.2	$0.2	($0.4)	($0.4)	$1.9	1%
23	Collier - Elwyn	Line	DLCO	$1.8	$0.1	$0.0	$1.8	($0.0)	($0.1)	($0.0)	$0.0	$1.8	1%
24	Sammis - Wylie Ridge	Line	AP	$2.5	$0.3	$0.1	$2.3	($0.4)	($0.2)	($0.3)	($0.5)	$1.7	1%
25	Harrison - Pruntytown	Line	500	$1.0	($0.8)	$0.3	$2.1	($0.3)	($0.4)	($0.6)	($0.5)	$1.6	1%

Table 7-15 Congestion cost by the type of the participant: January through March 2011 (New table)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Financial	$23.0	($0.0)	$10.6	$33.6	($3.9)	($1.7)	($40.0)	($42.2)	($8.5)
Physical	$153.4	($226.6)	($6.8)	$373.3	$26.1	$29.4	($0.6)	($3.9)	$369.4
Total	$176.4	($226.6)	$3.8	$406.9	$22.2	$27.7	($40.5)	($46.0)	$360.9

Table 7-16 Congestion cost by the type of the participant: January through March 2010 (New table)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Financial	($1.5)	$0.2	$10.5	$8.8	($11.1)	$5.2	($29.2)	($45.5)	($36.7)
Physical	$87.3	($293.5)	$2.4	$383.1	$5.1	$6.5	($0.0)	($1.4)	$381.8
Total	$85.8	($293.3)	$12.9	$391.9	($6.0)	$11.7	($29.2)	($46.9)	$345.1

Congestion-Event Summary for Midwest ISO Flowgates

Table 7-17 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through March 2011 (See 2010 SOM, Table 7-15)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	$1.5	($12.5)	($0.0)	$13.9	$3.7	$1.7	($0.8)	$1.2	$15.1	1,456	398
2	Pleasant Prairie - Zion	($0.1)	($0.8)	$0.0	$0.7	($0.1)	($0.2)	($6.2)	($6.2)	($5.4)	593	140
3	Lakeview - Pleasant Prairie	($0.0)	($0.1)	$0.0	$0.1	($0.2)	$0.0	($4.2)	($4.4)	($4.3)	24	164
4	Rising	$0.0	($0.5)	$0.0	$0.5	$0.0	$0.5	($2.3)	($2.8)	($2.2)	48	54
5	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	$1.0	$0.7	($2.3)	($2.0)	($2.0)	0	46
6	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($1.5)	($1.6)	($1.6)	0	52
7	Oak Grove - Galesburg	($0.1)	($0.3)	$0.0	$0.2	($0.1)	$0.3	($1.3)	($1.6)	($1.4)	52	62
8	Benton Harbor - Palisades	$0.7	($0.1)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	0	0
9	Monticello - Schahfer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.7)	($0.8)	($0.7)	17	45
10	Crete - St. Johns	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	62	0
11	Pierce - East Bend	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.5)	($0.5)	($0.5)	0	2
12	Bayshore	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	0	0
13	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	4
14	Roxana - Praxair	($0.0)	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.1	$0.2	$0.2	42	10
15	Babcock - Wilton Center	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	5
16	Rantoul - Wilton Center	$0.0	($0.2)	$0.0	$0.2	$0.0	$0.0	($0.1)	($0.1)	$0.1	37	25
17	Prairie State - Coffeen	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	15	28
18	Lakeview - Arcadian	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	102	0
19	Dunes Acres - Michigan City	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	4
20	Bunsonville - Eugene	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	36	0

Table 7-18 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through March 2010 (See 2010 SOM, Table 7-16)

		Congestion Costs (Millions)									Event Hours	
		Day Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Prairie - Zion	($2.4)	($5.9)	$1.5	$5.1	($0.5)	$1.0	($8.6)	($10.2)	($5.1)	556	110
2	Rising	$0.3	($3.4)	$0.4	$4.2	($0.0)	($0.0)	($0.0)	($0.0)	$4.1	582	32
3	Dunes Acres - Michigan City	$0.6	($1.1)	$0.4	$2.1	($0.0)	($0.0)	($0.0)	($0.0)	$2.1	142	3
4	State Line - Wolf Lake	$0.3	($0.4)	$0.5	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	269	0
5	Crete - St Johns Tap	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.3	129	1
6	Bunsonville - Eugene	($0.0)	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
7	Burr Oak	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	20	40
8	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	1
9	Powerton Jct. - Lilly	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	15
10	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	9
11	Oak Grove - Galesburg	($0.0)	($0.2)	$0.1	$0.2	$0.0	$0.0	($0.2)	($0.2)	$0.0	51	38
12	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	6
13	Coffeen North - Ramsey	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	3
14	Lanesville	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	2
15	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	0

Congestion-Event Summary for the 500 kV System

Table 7-19 Regional constraints summary (By facility): January through March 2011 (See 2010 SOM, Table 7-17)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$3.2	($129.5)	$0.0	$132.8	$7.8	$7.8	($0.7)	($0.7)	$132.1	1,172	513
2	5004/5005 Interface	Interface	500	$50.5	($13.2)	$0.0	$63.7	$5.6	$5.1	$3.6	$4.2	$67.9	513	241
3	Bedington - Black Oak	Interface	500	$5.3	($19.2)	$0.0	$24.5	$0.0	$0.0	$0.0	$0.0	$24.5	576	0
4	AEP-DOM	Interface	500	$1.5	($11.8)	$0.0	$13.2	$0.6	$0.3	($0.1)	$0.2	$13.4	293	88
5	West	Interface	500	$13.2	$3.4	$0.0	$9.8	$0.2	$0.0	$0.1	$0.3	$10.1	231	12
6	East	Interface	500	$4.5	($3.1)	$0.0	$7.7	$0.1	$1.2	$0.1	($1.0)	$6.7	127	22
7	Central	Interface	500	$1.4	$0.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	45	0
8	Harrison - Pruntytown	Line	500	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
9	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	9

Table 7-20 Regional constraints summary (By facility): January through March 2010 (See 2010 SOM, Table 7-18)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$7.1	($162.6)	($1.1)	$168.5	$4.4	$3.9	$1.2	$1.7	$170.2	1,255	735
2	AEP-DOM	Interface	500	$9.4	($37.8)	$0.9	$48.1	$0.2	($1.2)	$0.1	$1.6	$49.6	452	76
3	5004/5005 Interface	Interface	500	$24.1	($19.0)	($0.8)	$42.2	$1.0	$1.0	$0.2	$0.2	$42.5	806	294
4	Bedington - Black Oak	Interface	500	$4.1	($19.1)	($0.8)	$22.4	$0.4	($0.5)	$0.1	$0.9	$23.3	519	9
5	West	Interface	500	$2.5	($0.2)	$0.0	$2.7	$0.3	$0.4	$0.2	$0.1	$2.8	56	37
6	Harrison - Pruntytown	Line	500	$1.0	($0.8)	$0.3	$2.1	($0.3)	($0.4)	($0.6)	($0.5)	$1.6	75	85
7	Harrison Tap - North Longview	Line	500	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
8	Central	Interface	500	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0

Zonal Congestion

Summary

Table 7-21 Congestion cost summary (By control zone): January through March 2011 (See 2010 SOM, Table 7-19)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$14.1	$5.4	$0.2	$8.9	($0.4)	($0.2)	($0.4)	($0.6)	$8.3
AEP	($37.3)	($107.8)	$0.2	$70.6	($0.8)	$8.6	($2.6)	($11.9)	$58.7
AP	($6.2)	($75.2)	($4.1)	$65.0	$2.1	$3.3	$2.9	$1.7	$66.7
BGE	$38.7	$29.9	$1.3	$10.1	$2.5	($0.9)	($1.4)	$2.0	$12.0
ComEd	($130.9)	($192.5)	($4.9)	$56.7	$16.4	$7.8	($9.6)	($1.1)	$55.6
DAY	($6.4)	($8.6)	($0.3)	$1.9	$0.3	$2.1	($0.5)	($2.3)	($0.4)
DLCO	($23.4)	($36.5)	($0.5)	$12.6	($2.3)	($0.2)	$0.2	($1.9)	$10.7
DPL	$25.3	$5.8	$0.3	$19.8	$0.5	$0.2	($0.3)	($0.0)	$19.7
Dominion	$40.2	($17.4)	$2.5	$60.1	$0.3	$4.2	($2.1)	($6.0)	$54.1
External	($4.4)	($18.6)	$4.4	$18.6	$2.4	($6.3)	($14.7)	($6.0)	$12.6
JCPL	$31.6	$12.1	$0.1	$19.6	($0.5)	$0.2	($0.2)	($0.9)	$18.6
Met-Ed	$17.9	$20.2	$0.1	($2.2)	$0.5	($0.6)	($0.1)	$1.0	($1.2)
PECO	$53.2	$54.7	$0.5	($1.0)	($0.8)	$1.4	($0.3)	($2.6)	($3.6)
PENELEC	($10.7)	($39.4)	($0.8)	$28.0	$1.5	$2.1	$0.3	($0.2)	$27.7
PPL	$60.6	$62.6	$1.9	($0.1)	$3.7	($1.7)	($0.8)	$4.5	$4.4
PSEG	$57.5	$42.9	$1.1	$15.8	($1.1)	$9.4	($9.1)	($19.6)	($3.9)
Pepco	$55.4	$35.6	$1.7	$21.5	($1.9)	($1.9)	($1.8)	($1.8)	$19.8
RECO	$1.2	$0.2	$0.1	$1.1	$0.0	$0.1	($0.1)	($0.1)	$0.9
Total	$176.4	($226.6)	$3.8	$406.9	$22.2	$27.7	($40.5)	($46.0)	$360.9

Table 7-22 Congestion cost summary (By control zone): January through March 2010 (See 2010 SOM, Table 7-20)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$5.2	$2.5	$0.0	$2.7	$0.5	($0.0)	($0.0)	$0.5	$3.2
AEP	($16.0)	($86.7)	$3.1	$73.7	($6.5)	$3.7	($4.2)	($14.4)	$59.3
AP	($16.0)	($83.5)	($2.0)	$65.5	$2.7	$3.1	$1.6	$1.3	$66.8
BGE	$36.9	$27.6	$1.6	$10.9	$3.9	($1.5)	($1.5)	$3.8	$14.7
ComEd	($83.3)	($148.3)	($0.8)	$64.3	($3.6)	$3.2	($2.3)	($9.1)	$55.2
DAY	($3.7)	($7.1)	($0.1)	$3.2	$0.1	$0.6	$0.1	($0.4)	$2.8
DLCO	($32.5)	($49.5)	($0.1)	$16.9	($1.9)	($0.9)	($0.0)	($1.0)	$15.9
DPL	$12.0	$3.4	($0.1)	$8.5	$0.7	($0.4)	$0.1	$1.2	$9.7
Dominion	$66.5	($3.2)	$1.8	$71.6	$1.5	$3.0	($1.3)	($2.7)	$68.8
External	($19.1)	($26.7)	($2.2)	$5.5	$3.3	($2.0)	($9.2)	($3.9)	$1.5
JCPL	$10.6	$3.9	$0.0	$6.7	($0.0)	($0.2)	($0.1)	$0.1	$6.8
Met-Ed	$10.2	$7.3	($0.0)	$2.8	$0.0	($0.4)	($0.0)	$0.5	$3.3
PECO	$5.9	$15.4	$0.0	($9.5)	($0.1)	$0.2	($0.0)	($0.3)	($9.7)
PENELEC	($29.7)	($61.5)	($0.2)	$31.6	$2.4	($1.0)	$0.1	$3.5	$35.1
PPL	$24.9	$29.8	$0.9	($4.1)	$0.8	$0.4	($0.3)	$0.0	($4.1)
PSEG	$27.3	$20.5	$9.6	$16.5	($7.6)	$5.2	($10.6)	($23.3)	($6.9)
Pepco	$86.0	$62.7	$1.4	$24.7	($2.3)	($1.3)	($1.6)	($2.6)	$22.1
RECO	$0.6	$0.1	$0.0	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4
Total	$85.8	($293.3)	$12.9	$391.9	($6.0)	$11.7	($29.2)	($46.9)	$345.1

Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-23 AECO Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-21)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$5.4	$2.4	$0.0	$3.0	$0.2	($0.4)	($0.0)	$0.6	$3.6	513	241
2	Wylie Ridge	Transformer	AP	$2.1	$0.8	$0.0	$1.3	$0.1	($0.1)	($0.0)	$0.2	$1.5	1,235	329
3	West	Interface	500	$1.2	$0.4	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.0	$0.8	231	12
4	Shieldalloy - Vineland	Line	AECO	$0.9	$0.1	$0.0	$0.8	($0.8)	$0.5	($0.2)	($1.5)	($0.7)	126	45
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.8	$0.2	$0.0	$0.6	$0.0	($0.0)	$0.0	$0.0	$0.6	1,456	398
6	East	Interface	500	$1.1	$0.5	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	127	22
7	AP South	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	1,172	513
8	Bridgewater - Middlesex	Line	PSEG	$0.4	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	377	19
9	South Mahwah - Waldwick	Line	PSEG	$0.3	$0.1	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.3	1,730	203
10	Cedar Grove - Roseland	Line	PSEG	($0.2)	($0.1)	$0.0	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	713	26
11	Bedington - Black Oak	Interface	500	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	576	0
12	Wolfcreek	Transformer	AEP	$0.2	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	729	94
13	Plymouth Meeting - Whitpain	Line	PECO	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	86	65
14	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	25
15	Central	Interface	500	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	45	0
25	England - Merion	Line	AECO	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	7	0
26	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	($0.1)	71	18
30	Carnegie - Tidd	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	388	0
42	Sherman Avenue	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
67	Corson	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	4

Table 7-24 AECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-22)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$3.6	$1.8	$0.0	$1.9	$0.2	($0.0)	($0.0)	$0.3	$2.1	806	294
2	East Frankfort - Crete	Line	ComEd	$0.3	$0.1	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	835	419
3	AP South	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.3	1,255	735
4	Athenia - Saddlebrook	Line	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	1,779	273
5	West	Interface	500	$0.3	$0.1	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.2	56	37
6	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	697	140
7	Sammis - Wylie Ridge	Line	AP	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	305	37
8	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.1)	($0.1)	34	25
9	Bedington - Black Oak	Interface	500	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	519	9
10	Crescent	Transformer	DLCO	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	310	58
11	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	85
12	Cloverdale - Lexington	Line	AEP	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	154	97
13	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	75	33
14	Atlantic - Larrabee	Line	JCPL	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	88	6
15	AEP-DOM	Interface	500	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	452	76
46	Lindenwold - Stratford	Line	AECO	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	318	0
101	Pinehill - Stratford	Line	AECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	293	0
171	Berlin - Silver Lake	Line	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0

BGE Control Zone

Table 7-25 BGE Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-23)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$16.3	$14.4	$0.0	$1.9	$1.1	($0.5)	($0.5)	$1.1	$3.0	1,172	513
2	5004/5005 Interface	Interface	500	$5.8	$3.9	$0.0	$1.9	$0.3	($0.1)	($0.1)	$0.2	$2.1	513	241
3	Wylie Ridge	Transformer	AP	$5.3	$4.0	$0.0	$1.4	$0.3	($0.1)	($0.1)	$0.2	$1.6	1,235	329
4	West	Interface	500	$3.0	$1.5	$0.0	$1.5	$0.0	($0.1)	($0.0)	$0.1	$1.6	231	12
5	Bedington - Black Oak	Interface	500	$4.7	$3.7	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	576	0
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.5	$1.7	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.0	$0.8	1,456	398
7	Susquehanna	Transformer	PPL	($1.0)	($0.6)	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	120	0
8	Doubs	Transformer	AP	$0.5	$0.3	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.2	$0.3	38	51
9	Burches Hill	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	($0.1)	($0.0)	$0.3	$0.3	8	44
10	Bristers - Ox	Line	Dominion	$0.5	$0.3	$0.0	$0.2	$0.0	($0.1)	($0.0)	$0.1	$0.3	33	25
11	Wolfcreek	Transformer	AEP	$0.5	$0.3	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.3	729	94
12	Cloverdale - Lexington	Line	AEP	$0.5	$0.4	$0.0	$0.1	$0.2	($0.0)	($0.1)	$0.2	$0.2	173	155
13	Cedar Grove - Roseland	Line	PSEG	($0.5)	($0.3)	$0.0	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	713	26
14	Graceton - Raphael Road	Line	BGE	$0.3	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	16	11
15	East	Interface	500	($0.9)	($0.8)	$0.0	($0.1)	($0.0)	$0.1	$0.0	($0.1)	($0.2)	127	22
33	Riverside	Other	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2
47	Greene St - Westport	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	2
54	Conastone - Otter	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	12
62	Green Street - Westport	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
100	Brandon Shores - Riverside	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	24	0

Table 7-26 BGE Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-24)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$19.6	$15.5	$0.8	$4.9	$2.0	($0.8)	($0.8)	$2.0	$7.0	1,255	735
2	5004/5005 Interface	Interface	500	$4.1	$2.1	$0.2	$2.3	$0.2	($0.2)	($0.1)	$0.2	$2.5	806	294
3	Bedington - Black Oak	Interface	500	$4.0	$3.0	$0.2	$1.2	$0.2	($0.0)	($0.0)	$0.2	$1.4	519	9
4	East Frankfort - Crete	Line	ComEd	$1.1	$0.8	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.6	835	419
5	AEP-DOM	Interface	500	$3.1	$2.8	$0.1	$0.3	$0.2	($0.0)	($0.0)	$0.2	$0.5	452	76
6	West	Interface	500	$0.6	$0.4	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.4	56	37
7	Mount Storm - Pruntytown	Line	AP	$0.6	$0.5	$0.0	$0.2	$0.1	($0.1)	($0.0)	$0.2	$0.3	87	64
8	Harrison - Pruntytown	Line	500	$0.2	$0.2	$0.0	$0.1	$0.2	($0.1)	($0.0)	$0.2	$0.3	75	85
9	Graceton - Raphael Road	Line	BGE	$0.6	$0.3	$0.0	$0.3	$0.1	$0.1	($0.1)	($0.0)	$0.3	34	25
10	Doubs	Transformer	AP	$0.2	$0.1	$0.0	$0.1	$0.1	($0.2)	($0.0)	$0.2	$0.3	75	33
11	Sammis - Wylie Ridge	Line	AP	$0.5	$0.4	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	305	37
12	Cloverdale - Lexington	Line	AEP	$0.3	$0.3	$0.0	$0.1	$0.1	($0.0)	($0.1)	$0.1	$0.2	154	97
13	Athenia - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.2)	1,779	273
14	Tiltonsville - Windsor	Line	AP	$0.4	$0.3	$0.0	$0.1	$0.1	$0.0	($0.0)	$0.0	$0.1	697	140
15	Nipetown - Reid	Line	AP	$0.3	$0.2	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	18
23	Fullerton - Windyedge	Line	BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
30	Graceton - Safe Harbor	Line	BGE	$0.2	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	15	1
45	Brandon Shores - Riverside	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	5	15
53	Conastone - Otter	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	3	1
65	Glenarm - Windy Edge	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0

DPL Control Zone

Table 7-27 DPL Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-25)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$10.2	$2.6	$0.0	$7.6	$0.2	($0.0)	($0.1)	$0.1	$7.7	513	241
2	Wylie Ridge	Transformer	AP	$4.1	$0.8	$0.0	$3.3	$0.1	$0.0	($0.0)	$0.0	$3.3	1,235	329
3	West	Interface	500	$2.2	$0.7	$0.0	$1.5	$0.0	($0.0)	($0.0)	$0.0	$1.5	231	12
4	East	Interface	500	$2.1	$0.5	$0.0	$1.6	($0.0)	$0.1	($0.0)	($0.1)	$1.5	127	22
5	AP South	Interface	500	$1.9	$0.4	$0.0	$1.5	$0.1	$0.0	($0.1)	($0.0)	$1.4	1,172	513
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.6	$0.2	$0.0	$1.4	$0.0	$0.0	($0.0)	($0.0)	$1.3	1,456	398
7	Bedington - Black Oak	Interface	500	$0.8	$0.2	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	576	0
8	Plymouth Meeting - Whitpain	Line	PECO	$0.6	$0.1	$0.0	$0.5	$0.1	$0.0	($0.0)	$0.0	$0.5	86	65
9	Susquehanna	Transformer	PPL	($0.5)	($0.1)	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	120	0
10	Longwood - Wye Mills	Line	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	184	0
11	Central	Interface	500	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	45	0
12	Bradford - Planebrook	Line	PECO	($0.4)	($0.2)	$0.0	($0.3)	($0.1)	($0.0)	$0.0	($0.1)	($0.3)	61	28
13	Butler - Karns City	Line	AP	$0.3	$0.1	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	369	44
14	South Mahwah - Waldwick	Line	PSEG	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.2	1,730	203
15	Wolfcreek	Transformer	AEP	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	729	94
24	Kenney - Mount Olive	Line	DPL	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	33	2
30	Bellehaven - Tasley	Line	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	159	0
34	Easton	Transformer	DPL	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	24	2
40	Lumspond - Reybold	Line	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
45	Hallwood - Oak Hall	Line	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	44	0

Table 7-28 DPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-26)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$7.0	$2.1	$0.0	$4.9	$0.2	$0.1	($0.0)	$0.1	$5.0	806	294
2	AP South	Interface	500	$2.0	$0.7	($0.0)	$1.3	$0.1	$0.0	$0.0	$0.1	$1.4	1,255	735
3	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	8
4	East Frankfort - Crete	Line	ComEd	$0.7	$0.1	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	835	419
5	Bedington - Black Oak	Interface	500	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	519	9
6	West	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.1	$0.1	($0.0)	$0.0	$0.3	56	37
7	Sammis - Wylie Ridge	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	305	37
8	Athenia - Saddlebrook	Line	PSEG	($0.4)	($0.1)	($0.0)	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.3)	1,779	273
9	Tiltonsville - Windsor	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	697	140
10	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	429	0
11	Graceton - Raphael Road	Line	BGE	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	($0.0)	($0.2)	34	25
12	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.1	75	85
13	Cloverdale - Lexington	Line	AEP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	154	97
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	142	3
15	Longwood - Wye Mills	Line	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
18	Cecil - Colora	Line	DPL	$0.0	($0.0)	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.1)	($0.1)	17	4
26	New Church - Piney Grove	Line	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	49	0
28	Oak Hall	Transformer	DPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	53	0
30	Hallwood - Oak Hall	Line	DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	119	0
32	Church	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

JCPL Control Zone

Table 7-29 JCPL Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-27)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$13.5	$4.8	$0.0	$8.7	$0.0	$0.1	($0.0)	($0.1)	$8.6	513	241
2	Wylie Ridge	Transformer	AP	$4.7	$1.7	$0.0	$2.9	$0.0	$0.1	($0.0)	($0.1)	$2.9	1,235	329
3	Cedar Grove - Roseland	Line	PSEG	($2.7)	($0.8)	$0.0	($1.9)	$0.0	$0.0	$0.0	($0.0)	($1.9)	713	26
4	Bridgewater - Middlesex	Line	PSEG	$3.0	$1.1	$0.0	$1.9	($0.1)	$0.1	($0.0)	($0.2)	$1.8	377	19
5	South Mahwah - Waldwick	Line	PSEG	$2.3	$0.7	$0.0	$1.6	($0.1)	($0.1)	($0.1)	($0.1)	$1.5	1,730	203
6	West	Interface	500	$2.6	$1.2	$0.0	$1.3	($0.0)	($0.0)	($0.0)	($0.0)	$1.3	231	12
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.9	$0.7	$0.0	$1.1	$0.0	$0.0	($0.0)	$0.0	$1.2	1,456	398
8	East	Interface	500	$2.0	$0.8	$0.0	$1.2	($0.1)	$0.0	($0.0)	($0.1)	$1.1	127	22
9	Susquehanna	Transformer	PPL	$1.1	$0.3	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	120	0
10	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	49	0
11	Montville - Roseland	Line	PSEG	($0.3)	($0.0)	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	44	0
12	Roseland - West Caldwell	Line	PSEG	($0.4)	($0.1)	$0.0	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	71	10
13	Central	Interface	500	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	45	0
14	Butler - Karns City	Line	AP	$0.4	$0.2	$0.0	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	369	44
15	AP South	Interface	500	($0.0)	$0.2	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.0)	($0.2)	1,172	513
19	Kilmer - Sayreville	Line	JCPL	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	92	0
45	Redoak - Sayreville	Line	JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	19	0
59	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0

Table 7-30 JCPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-28)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$8.6	$3.1	$0.0	$5.5	$0.0	($0.2)	($0.0)	$0.3	$5.8	806	294
2	Athenia - Saddlebrook	Line	PSEG	($2.1)	($0.6)	($0.0)	($1.6)	($0.1)	$0.0	$0.0	($0.2)	($1.7)	1,779	273
3	East Frankfort - Crete	Line	ComEd	$0.9	$0.3	($0.0)	$0.5	$0.0	($0.0)	$0.0	$0.1	$0.6	835	419
4	West	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	56	37
5	Atlantic - Larrabee	Line	JCPL	$0.2	($0.1)	$0.0	$0.3	$0.0	$0.0	($0.0)	$0.0	$0.3	88	6
6	Sammis - Wylie Ridge	Line	AP	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	305	37
7	Bridgewater - Middlesex	Line	PSEG	$0.1	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.2)	25	5
8	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	26	0
9	Tiltonsville - Windsor	Line	AP	$0.3	$0.2	$0.0	$0.2	($0.0)	($0.0)	($0.0)	$0.0	$0.2	697	140
10	Bedington - Black Oak	Interface	500	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	519	9
11	AEP-DOM	Interface	500	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	452	76
12	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	85
13	Branchburg - Readington	Line	PSEG	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	180	0
14	Kilmer - Sayreville	Line	JCPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	72	0
15	Crescent	Transformer	DLCO	($0.2)	($0.1)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	310	58
23	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0

Met-Ed Control Zone

Table 7-31 Met-Ed Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-29)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Wylie Ridge	Transformer	AP	$3.3	$4.7	$0.0	($1.4)	$0.1	($0.0)	($0.0)	$0.1	($1.2)	1,235	329
2	West	Interface	500	$1.7	$2.3	$0.0	($0.6)	$0.0	$0.0	($0.0)	($0.0)	($0.6)	231	12
3	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.2	$1.7	$0.0	($0.5)	$0.0	($0.0)	($0.0)	$0.0	($0.5)	1,456	398
4	Susquehanna	Transformer	PPL	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	120	0
5	East	Interface	500	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	127	22
6	5004/5005 Interface	Interface	500	$8.3	$8.7	$0.0	($0.4)	$0.2	($0.3)	$0.0	$0.6	$0.2	513	241
7	Cedar Grove - Roseland	Line	PSEG	($0.7)	($0.8)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	713	26
8	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	0	52
9	Wolfcreek	Transformer	AEP	$0.3	$0.4	$0.0	($0.1)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	729	94
10	Montville - Roseland	Line	PSEG	($0.1)	($0.2)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	44	0
11	Hunterstown	Transformer	Met-Ed	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	9	5
12	Branchburg - Readington	Line	PSEG	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	150	26
13	Carnegie - Tidd	Line	AEP	$0.1	$0.2	$0.0	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	323	202
14	Benton Harbor - Palisades	Flowgate	Midwest ISO	$0.1	$0.1	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	0	46
15	Burches Hill	Transformer	Pepco	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	8	44
66	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
76	Hosensack - N.Temple	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Table 7-32 Met-Ed Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-30)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$5.9	$4.9	$0.0	$1.0	$0.0	($0.4)	($0.0)	$0.4	$1.5	806	294
2	AP South	Interface	500	$2.0	$1.0	($0.0)	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,255	735
3	West	Interface	500	$0.4	$0.2	$0.0	$0.2	$0.0	($0.1)	($0.0)	$0.1	$0.3	56	37
4	Athenia - Saddlebrook	Line	PSEG	($0.7)	($0.6)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.1)	($0.2)	1,779	273
5	Bedington - Black Oak	Interface	500	$0.6	$0.4	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.2	519	9
6	AEP-DOM	Interface	500	$0.1	($0.0)	($0.0)	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	452	76
7	East Frankfort - Crete	Line	ComEd	$0.6	$0.6	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	835	419
8	Sammis - Wylie Ridge	Line	AP	$0.3	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.1	305	37
9	Susquehanna	Transformer	PPL	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	36	0
10	Cloverdale - Lexington	Line	AEP	$0.1	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	154	97
11	Harrison - Pruntytown	Line	500	$0.1	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	75	85
12	Graceton - Raphael Road	Line	BGE	($0.2)	($0.2)	($0.0)	($0.0)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	34	25
13	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.1	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	142	3
14	Nipetown - Reid	Line	AP	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	75	18
15	Graceton - Safe Harbor	Line	BGE	($0.1)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	15	1
30	Collins - Middletown Jct	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
33	Brunner Island - Yorkana	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
110	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

PECO Control Zone

Table 7-33 PECO Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$21.2	$23.1	$0.0	($1.8)	($0.4)	$0.6	($0.1)	($1.0)	($2.8)	513	241
2	Plymouth Meeting - Whitpain	Line	PECO	$2.7	$0.3	$0.0	$2.4	($0.1)	$0.0	($0.0)	($0.1)	$2.3	86	65
3	AP South	Interface	500	$2.5	$4.5	$0.0	($2.0)	($0.0)	$0.0	($0.1)	($0.1)	($2.1)	1,172	513
4	West	Interface	500	$4.2	$6.3	$0.0	($2.1)	($0.0)	($0.0)	($0.0)	$0.0	($2.1)	231	12
5	Wylie Ridge	Transformer	AP	$8.0	$9.8	$0.0	($1.9)	($0.1)	$0.1	($0.0)	($0.2)	($2.1)	1,235	329
6	East	Interface	500	$3.8	$1.9	$0.0	$1.9	($0.1)	$0.1	($0.0)	($0.2)	$1.7	127	22
7	Bradford - Planebrook	Line	PECO	$0.9	($0.6)	$0.0	$1.5	$0.1	$0.2	$0.0	($0.1)	$1.5	61	28
8	Limerick	Transformer	PECO	$1.7	$0.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	30	0
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.1	$4.1	$0.0	($1.0)	($0.1)	$0.0	($0.0)	($0.1)	($1.1)	1,456	398
10	Susquehanna	Transformer	PPL	($0.7)	($1.5)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	120	0
11	Bedington - Black Oak	Interface	500	$1.1	$1.8	$0.0	($0.7)	$0.0	$0.0	$0.0	$0.0	($0.7)	576	0
12	Wolfcreek	Transformer	AEP	$0.6	$1.0	$0.0	($0.4)	$0.0	$0.0	($0.0)	($0.0)	($0.4)	729	94
13	Cedar Grove - Roseland	Line	PSEG	($0.9)	($1.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	713	26
14	Bristers - Ox	Line	Dominion	$0.3	$0.5	$0.0	($0.2)	($0.0)	$0.1	($0.0)	($0.1)	($0.3)	33	25
15	Eddystone - Saville	Line	PECO	$0.2	($0.1)	$0.0	$0.3	$0.0	$0.1	$0.0	($0.0)	$0.3	64	16
27	North Philadelphia - Waneeta	Line	PECO	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	195	3
32	Chichester	Transformer	PECO	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
33	Morton - Rid	Line	PECO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
40	Eddystone - Scott Paper	Line	PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
41	Flint - Plymouth Meeting	Line	PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	1	2

Table 7-34 PECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-32)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$3.9	$8.8	$0.0	($4.9)	($0.1)	($0.1)	($0.0)	($0.0)	($4.9)	806	294
2	AP South	Interface	500	$0.6	$3.0	$0.0	($2.4)	($0.0)	$0.1	$0.0	($0.1)	($2.5)	1,255	735
3	Bedington - Black Oak	Interface	500	$0.2	$0.7	$0.0	($0.5)	$0.0	$0.0	$0.0	($0.0)	($0.6)	519	9
4	East Frankfort - Crete	Line	ComEd	$0.6	$1.2	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	835	419
5	West	Interface	500	$0.4	$1.0	$0.0	($0.5)	($0.0)	($0.1)	$0.0	$0.1	($0.4)	56	37
6	AEP-DOM	Interface	500	($0.2)	$0.1	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	452	76
7	Sammis - Wylie Ridge	Line	AP	$0.3	$0.6	$0.0	($0.3)	($0.0)	($0.0)	$0.0	($0.0)	($0.3)	305	37
8	Graceton - Raphael Road	Line	BGE	($0.0)	($0.3)	$0.0	$0.2	$0.1	$0.1	$0.0	($0.0)	$0.2	34	25
9	Athenia - Saddlebrook	Line	PSEG	($0.3)	($0.7)	($0.0)	$0.5	$0.0	$0.3	$0.0	($0.3)	$0.2	1,779	273
10	Tiltonsville - Windsor	Line	AP	$0.2	$0.5	$0.0	($0.3)	($0.0)	($0.1)	($0.0)	$0.1	($0.2)	697	140
11	Harrison - Pruntytown	Line	500	$0.1	$0.1	$0.0	($0.1)	($0.0)	$0.0	$0.0	($0.1)	($0.1)	75	85
12	Burlington - Croydon	Line	PECO	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	512	13
13	Crescent	Transformer	DLCO	($0.0)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	310	58
14	Nipetown - Reid	Line	AP	$0.0	$0.1	$0.0	($0.1)	($0.0)	($0.0)	$0.0	($0.0)	($0.1)	75	18
15	Rising	Flowgate	Midwest ISO	$0.1	$0.1	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	$0.0	($0.1)	582	32
24	Cromby	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	33	2
39	Eddystone - Scott Paper	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	4
50	Holmesburg - Richmond	Line	PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	49	0
67	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
86	Eddystone - Saville	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	1

PENELEC Control Zone

Table 7-35 PENELEC Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-33)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($5.4)	($26.1)	$0.0	$20.6	$0.9	$1.4	$1.2	$0.7	$21.3	513	241
2	AP South	Interface	500	($11.2)	($20.5)	$0.0	$9.3	$1.5	$0.5	$0.6	$1.6	$10.9	1,172	513
3	Wylie Ridge	Transformer	AP	$2.8	$12.5	$0.0	($9.7)	($0.3)	($0.3)	($0.4)	($0.4)	($10.1)	1,235	329
4	West	Interface	500	($0.9)	($3.7)	$0.0	$2.8	$0.0	$0.1	$0.1	$0.0	$2.8	231	12
5	Bedington - Black Oak	Interface	500	($2.5)	($4.8)	$0.0	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	576	0
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.2	$4.0	$0.0	($1.8)	($0.1)	($0.0)	($0.1)	($0.1)	($1.9)	1,456	398
7	Susquehanna	Transformer	PPL	$0.6	($1.1)	$0.0	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	120	0
8	Butler - Karns City	Line	AP	$4.6	$2.9	$0.0	$1.6	($0.1)	$0.0	($0.1)	($0.3)	$1.3	369	44
9	East	Interface	500	($0.4)	($1.2)	$0.0	$0.7	$0.0	$0.1	$0.1	$0.0	$0.8	127	22
10	South Mahwah - Waldwick	Line	PSEG	($1.8)	($1.6)	$0.0	($0.2)	$0.2	$0.1	($0.6)	($0.5)	($0.7)	1,730	203
11	Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.0)	($0.0)	$0.3	$0.3	$0.6	713	26
12	AEP-DOM	Interface	500	($0.7)	($1.1)	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	293	88
13	Carnegie - Tidd	Line	AEP	$0.1	$0.5	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.1)	($0.4)	323	202
14	Tiltonsville - Windsor	Line	AP	$0.2	$0.5	$0.0	($0.3)	($0.0)	($0.0)	($0.1)	($0.1)	($0.4)	223	45
15	Wolfcreek	Transformer	AEP	$0.5	$0.7	$0.0	($0.3)	($0.0)	($0.0)	($0.1)	($0.0)	($0.3)	729	94
18	Erie West	Transformer	PENELEC	$0.5	($0.0)	$0.0	$0.5	($0.3)	$0.2	($0.2)	($0.7)	($0.2)	287	30
22	Garret Tap - Garrett	Line	PENELEC	$0.4	$0.3	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	20	0
27	Keystone - Shelocta	Line	PENELEC	($0.2)	($0.1)	$0.0	($0.1)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	12	4
28	Elko - Forest	Line	PENELEC	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	50	0
40	Blairsville East	Transformer	PENELEC	($0.6)	($0.6)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	53	6

Table 7-36 PENELEC Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-34)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($21.9)	($33.6)	($0.0)	$11.7	$1.6	($1.3)	$0.1	$3.0	$14.7	1,255	735
2	5004/5005 Interface	Interface	500	($6.4)	($20.5)	($0.1)	$14.0	$0.4	($0.0)	$0.1	$0.5	$14.5	806	294
3	Bedington - Black Oak	Interface	500	($3.8)	($5.8)	($0.0)	$2.1	$0.1	($0.0)	$0.0	$0.1	$2.2	519	9
4	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.1	($0.1)	$0.0	$0.2	$2.1	452	76
5	East Frankfort - Crete	Line	ComEd	$2.0	$2.5	$0.0	($0.5)	($0.4)	$0.1	($0.0)	($0.5)	($1.0)	835	419
6	Sammis - Wylie Ridge	Line	AP	$0.3	$1.1	$0.0	($0.8)	($0.1)	($0.1)	($0.0)	($0.0)	($0.8)	305	37
7	West	Interface	500	($0.3)	($0.9)	$0.0	$0.7	$0.2	$0.0	$0.0	$0.1	$0.8	56	37
8	Homer City - Seward	Line	PENELEC	$1.4	$0.8	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	37	0
9	Mount Storm - Pruntytown	Line	AP	($0.6)	($1.0)	($0.0)	$0.4	$0.2	$0.1	$0.0	$0.1	$0.4	87	64
10	Seward	Transformer	PENELEC	$0.8	$0.4	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	22	0
11	Tiltonsville - Windsor	Line	AP	$0.7	$0.8	$0.0	($0.1)	($0.2)	$0.1	($0.0)	($0.2)	($0.4)	697	140
12	Altoona - Bear Rock	Line	PENELEC	($0.5)	($0.9)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	16	0
13	Homer City - Johnstown	Line	PENELEC	$0.9	$0.6	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	32	0
14	Homer City	Transformer	PENELEC	$0.7	$0.4	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	80	0
15	Crescent	Transformer	DLCO	($0.6)	($0.7)	($0.0)	$0.1	$0.1	($0.1)	$0.0	$0.1	$0.3	310	58
17	Garrett	Transformer	PENELEC	$1.1	$0.9	$0.0	$0.2	$0.0	$0.1	$0.0	($0.0)	$0.2	102	3
31	Keystone - Shelocta	Line	PENELEC	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
36	Deepcreek	Transformer	PENELEC	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	158	0
39	Homer City - Shelocta	Line	PENELEC	($0.0)	($0.0)	($0.0)	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	1	3
42	Roxbury - Shade Gap	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	0	5

Pepco Control Zone

Table 7-37 Pepco Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-35)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$29.2	$19.3	$0.0	$9.9	($1.2)	($1.2)	($0.6)	($0.6)	$9.3	1,172	513
2	Bedington - Black Oak	Interface	500	$7.8	$5.0	$0.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	576	0
3	Wylie Ridge	Transformer	AP	$6.4	$4.1	$0.0	$2.3	($0.1)	($0.2)	($0.1)	$0.0	$2.4	1,235	329
4	5004/5005 Interface	Interface	500	$3.8	$2.3	$0.0	$1.4	($0.1)	($0.1)	($0.1)	($0.1)	$1.3	513	241
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.3	$2.0	$0.0	$1.3	($0.1)	($0.1)	($0.0)	$0.0	$1.3	1,456	398
6	West	Interface	500	$2.6	$1.5	$0.0	$1.1	($0.0)	($0.0)	($0.0)	$0.0	$1.1	231	12
7	Susquehanna	Transformer	PPL	($1.4)	($0.8)	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	120	0
8	AEP-DOM	Interface	500	$1.6	$1.1	$0.0	$0.5	($0.0)	($0.1)	($0.0)	$0.0	$0.5	293	88
9	East	Interface	500	($1.3)	($0.9)	$0.0	($0.4)	$0.0	$0.1	$0.0	($0.1)	($0.5)	127	22
10	Cloverdale - Lexington	Line	AEP	$0.8	$0.5	$0.0	$0.3	($0.1)	($0.1)	($0.1)	($0.0)	$0.2	173	155
11	Wolfcreek	Transformer	AEP	$0.7	$0.4	$0.0	$0.3	($0.0)	($0.0)	($0.1)	($0.1)	$0.2	729	94
12	Bristers - Ox	Line	Dominion	$0.9	$0.6	$0.0	$0.3	($0.3)	($0.2)	($0.0)	($0.1)	$0.2	33	25
13	Doubs	Transformer	AP	$0.9	$0.5	$0.0	$0.4	($0.1)	$0.1	($0.1)	($0.2)	$0.2	38	51
14	Burches Hill	Transformer	Pepco	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	8	44
15	Limerick	Transformer	PECO	($0.3)	($0.1)	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	30	0
101	Buzzard - Ritchie	Line	Pepco	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	64	0
107	Dickerson - Quince Orchard	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	2	4
171	Benning	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0

Table 7-38 Pepco Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-36)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$48.2	$36.4	$0.6	$12.5	($1.0)	($0.4)	($0.8)	($1.5)	$11.0	1,255	735
2	Bedington - Black Oak	Interface	500	$9.7	$6.8	$0.2	$3.1	($0.0)	($0.1)	($0.0)	$0.1	$3.1	519	9
3	AEP-DOM	Interface	500	$8.0	$6.5	$0.1	$1.5	($0.1)	($0.2)	($0.1)	$0.0	$1.5	452	76
4	5004/5005 Interface	Interface	500	$4.4	$3.0	$0.2	$1.5	($0.1)	$0.0	($0.1)	($0.2)	$1.3	806	294
5	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
6	East Frankfort - Crete	Line	ComEd	$2.1	$1.3	$0.0	$0.8	($0.2)	($0.0)	($0.0)	($0.2)	$0.6	835	419
7	Mount Storm - Pruntytown	Line	AP	$1.5	$1.0	$0.0	$0.5	($0.2)	($0.3)	($0.0)	$0.1	$0.6	87	64
8	Benning - Ritchie	Line	Pepco	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	19	0
9	Sammis - Wylie Ridge	Line	AP	$0.9	$0.6	$0.0	$0.3	($0.1)	($0.1)	($0.0)	$0.0	$0.4	305	37
10	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	9
11	Tiltonsville - Windsor	Line	AP	$0.8	$0.5	$0.0	$0.3	($0.1)	($0.0)	($0.0)	($0.1)	$0.2	697	140
12	Harrison - Pruntytown	Line	500	$0.5	$0.4	$0.0	$0.1	($0.1)	($0.3)	($0.0)	$0.1	$0.2	75	85
13	Athenia - Saddlebrook	Line	PSEG	($0.1)	($0.1)	($0.0)	($0.1)	$0.1	($0.1)	$0.2	$0.3	$0.2	1,779	273
14	Burtonsville - Metzerott Rd.	Line	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	17	0
15	Doubs	Transformer	AP	$0.5	$0.3	$0.0	$0.2	($0.1)	$0.2	($0.1)	($0.4)	($0.2)	75	33
32	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	53	3
34	Burches Hill - Talbert	Line	Pepco	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	1	13
54	Buzzard - Ritchie	Line	Pepco	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

PPL Control Zone

Table 7-39 PPL Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-37)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Susquehanna	Transformer	PPL	$12.6	$2.7	$0.0	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	120	0
2	5004/5005 Interface	Interface	500	$28.2	$36.8	$0.0	($8.6)	$1.4	($0.3)	($0.3)	$1.4	($7.2)	513	241
3	Wylie Ridge	Transformer	AP	$8.9	$11.5	$0.0	($2.6)	$0.5	($0.0)	($0.1)	$0.5	($2.1)	1,235	329
4	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.6	($1.3)	($0.2)	$1.7	$1.7	0	52
5	West	Interface	500	$4.4	$5.7	$0.0	($1.3)	$0.0	($0.1)	($0.0)	$0.1	($1.2)	231	12
6	AP South	Interface	500	$0.1	($1.0)	$0.0	$1.1	$0.1	$0.1	$0.0	$0.0	$1.1	1,172	513
7	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.4	$4.5	($0.0)	($1.1)	$0.1	$0.0	($0.0)	$0.1	($0.9)	1,456	398
8	East	Interface	500	($0.0)	($0.9)	$0.0	$0.9	$0.0	$0.0	$0.1	$0.1	$0.9	127	22
9	Cedar Grove - Roseland	Line	PSEG	($1.9)	($2.3)	$0.0	$0.4	($0.1)	($0.0)	$0.0	($0.1)	$0.4	713	26
10	South Mahwah - Waldwick	Line	PSEG	$1.0	$1.2	$0.0	($0.2)	$0.1	$0.1	($0.1)	($0.1)	($0.3)	1,730	203
11	Central	Interface	500	$0.6	$0.8	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	45	0
12	Benton Harbor - Palisades	Flowgate	Midwest ISO	$0.2	$0.2	$0.0	($0.1)	$0.1	($0.0)	$0.0	$0.1	$0.1	0	46
13	Burches Hill	Transformer	Pepco	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.0)	$0.2	$0.1	8	44
14	Wolfcreek	Transformer	AEP	$0.7	$0.9	$0.0	($0.2)	$0.1	($0.0)	($0.0)	$0.1	($0.1)	729	94
15	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	($0.9)	$0.0	$0.2	($0.1)	$0.0	$0.0	($0.1)	$0.1	86	65
23	Blooming Grove - Peckville	Line	PPL	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	9	0
50	Wescosville	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	1

Table 7-40 PPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-38)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$19.1	$24.2	$0.5	($4.6)	$0.3	$0.3	($0.2)	($0.1)	($4.7)	806	294
2	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	36	0
3	AP South	Interface	500	$1.1	$0.7	$0.2	$0.5	$0.1	($0.1)	($0.1)	$0.1	$0.6	1,255	735
4	East Frankfort - Crete	Line	ComEd	$1.6	$2.1	$0.0	($0.5)	$0.1	$0.0	($0.0)	$0.1	($0.3)	835	419
5	Sammis - Wylie Ridge	Line	AP	$0.8	$1.0	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.0)	($0.3)	305	37
6	West	Interface	500	$1.1	$1.3	$0.0	($0.1)	($0.0)	$0.1	($0.0)	($0.1)	($0.2)	56	37
7	Bedington - Black Oak	Interface	500	$0.5	$0.4	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.2	519	9
8	Hawthorn - Waldwick	Line	PSEG	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	454	36
9	Tiltonsville - Windsor	Line	AP	$0.5	$0.7	$0.0	($0.1)	$0.1	$0.0	($0.0)	$0.0	($0.1)	697	140
10	Baker - Broadford	Line	AEP	($0.0)	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	10	74
11	Athenia - Saddlebrook	Line	PSEG	($1.8)	($2.0)	($0.0)	$0.1	($0.1)	$0.1	$0.1	($0.1)	$0.1	1,779	273
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$0.3	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	142	3
13	Rising	Flowgate	Midwest ISO	$0.2	$0.3	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)	582	32
14	Crescent	Transformer	DLCO	($0.3)	($0.4)	($0.0)	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	310	58
15	Graceton - Safe Harbor	Line	BGE	($0.2)	($0.2)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	15	1
36	Wescosville	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

PSEG Control Zone

Table 7-41 PSEG Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-39)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Cedar Grove - Roseland	Line	PSEG	$6.0	$0.9	$0.0	$5.1	($0.1)	$0.6	($0.1)	($0.7)	$4.4	713	26
2	AP South	Interface	500	($0.8)	$1.9	$0.0	($2.7)	$0.1	($0.3)	($0.7)	($0.4)	($3.0)	1,172	513
3	5004/5005 Interface	Interface	500	$17.0	$16.4	$0.0	$0.6	$0.1	$2.8	($0.6)	($3.3)	($2.7)	513	241
4	South Mahwah - Waldwick	Line	PSEG	$9.0	$1.7	$0.0	$7.3	($0.9)	$2.5	($5.8)	($9.2)	($1.9)	1,730	203
5	Wylie Ridge	Transformer	AP	$6.3	$6.6	$0.0	($0.3)	$0.0	$0.9	($0.2)	($1.1)	($1.4)	1,235	329
6	Susquehanna	Transformer	PPL	$1.2	($0.1)	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	120	0
7	East	Interface	500	$2.8	$3.4	$0.0	($0.5)	($0.1)	$0.5	($0.1)	($0.7)	($1.3)	127	22
8	Branchburg - Readington	Line	PSEG	$1.3	$0.0	$0.0	$1.3	($0.1)	$0.3	($0.0)	($0.4)	$0.9	150	26
9	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	0
10	Roseland - West Caldwell	Line	PSEG	$1.0	$0.1	$0.0	$1.0	($0.0)	$0.2	($0.1)	($0.3)	$0.7	71	10
11	Bedington - Black Oak	Interface	500	$0.3	$1.0	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	576	0
12	Montville - Roseland	Line	PSEG	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	44	0
13	Plymouth Meeting - Whitpain	Line	PECO	($0.2)	$0.4	$0.0	($0.6)	$0.0	($0.1)	($0.0)	$0.1	($0.5)	86	65
14	Bradford - Planebrook	Line	PECO	$0.5	($0.0)	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	61	28
15	Limerick	Transformer	PECO	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	30	0
20	Waldwick	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.2)	($0.3)	($0.3)	0	7
21	Cedar Grove - Clifton	Line	PSEG	$0.3	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	62	0
22	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.2)	($0.2)	0	52
23	Bridgewater - Middlesex	Line	PSEG	($0.1)	$0.0	$0.0	($0.2)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	377	19
29	Cook Rd - West Caldwell	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	13	0

Table 7-42 PSEG Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-40)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.6)	($3.4)	($3.4)	454	36
2	AP South	Interface	500	$0.2	$2.4	$1.1	($1.1)	$0.1	($0.2)	($0.9)	($0.6)	($1.7)	1,255	735
3	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	209	35
4	5004/5005 Interface	Interface	500	$12.0	$12.6	$1.2	$0.6	($0.1)	$0.7	($0.5)	($1.4)	($0.8)	806	294
5	Bayonne - PVSC	Line	PSEG	$0.0	($0.4)	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	507	0
6	Branchburg - Readington	Line	PSEG	$0.5	$0.0	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	180	0
7	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	170	0
8	Graceton - Raphael Road	Line	BGE	($0.3)	($0.4)	($0.0)	$0.0	$0.2	($0.1)	$0.1	$0.4	$0.4	34	25
9	East Frankfort - Crete	Line	ComEd	$1.3	$1.4	$0.0	($0.0)	($0.1)	$0.2	($0.1)	($0.3)	($0.4)	835	419
10	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($0.0)	($0.0)	$0.1	$0.1	($0.0)	$0.0	($0.5)	($0.5)	($0.4)	556	110
11	Athenia - Saddlebrook	Line	PSEG	$9.4	$1.3	$5.3	$13.4	($6.5)	$2.7	($4.6)	($13.7)	($0.4)	1,779	273
12	West	Interface	500	$0.8	$0.8	$0.1	$0.1	($0.1)	$0.2	($0.1)	($0.4)	($0.4)	56	37
13	Bedington - Black Oak	Interface	500	$0.3	$0.8	$0.3	($0.3)	$0.0	($0.0)	($0.0)	($0.0)	($0.3)	519	9
14	Saddlebrook	Transformer	PSEG	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	308	0
15	Atlantic - Larrabee	Line	JCPL	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	88	6
16	Fairlawn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.2)	0	4
18	Fairlawn - Saddlebrook	Line	PSEG	$0.2	$0.1	$0.3	$0.4	($0.0)	$0.1	($0.4)	($0.5)	($0.2)	209	16
19	Hudson	Transformer	PSEG	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	30	0
20	Bayway - Federal Square	Line	PSEG	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	109	1
22	Linden - North Ave	Line	PSEG	$0.1	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	66	1

RECO Control Zone

Table 7-43 RECO Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-41)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	($0.7)	($0.2)	$0.0	($0.5)	$0.0	$0.3	$0.0	($0.3)	($0.8)	1,730	203
2	5004/5005 Interface	Interface	500	$0.7	$0.1	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.0	$0.6	513	241
3	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.2	713	26
4	Wylie Ridge	Transformer	AP	$0.2	$0.1	$0.0	$0.2	($0.0)	($0.0)	($0.0)	$0.0	$0.2	1,235	329
5	West	Interface	500	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	231	12
6	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	1,456	398
7	East	Interface	500	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	127	22
8	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	150	26
9	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	1,172	513
10	Susquehanna	Transformer	PPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	120	0
11	Roseland - West Caldwell	Line	PSEG	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	71	10
12	Montville - Roseland	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	44	0
13	Wolfcreek	Transformer	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	729	94
14	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	38	51
15	Plymouth Meeting - Whitpain	Line	PECO	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.0)	86	65

Table 7-44 RECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-42)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.4	806	294
2	Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.1	$0.2	1,779	273
3	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	1,255	735
4	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	209	35
5	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	454	36
6	East Frankfort - Crete	Line	ComEd	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	835	419
7	West	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	56	37
8	Tiltonsville - Windsor	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	697	140
9	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	209	16
10	AEP-DOM	Interface	500	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	452	76
11	Crescent	Transformer	DLCO	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	310	58
12	Graceton - Raphael Road	Line	BGE	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	34	25
13	Fairlawn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	4
14	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	75	33
15	Sammis - Wylie Ridge	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	305	37

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-45 AEP Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-43)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($12.5)	($33.1)	$0.0	$20.6	($0.6)	$2.7	$1.0	($2.3)	$18.3	1,172	513
2	Belmont	Transformer	AP	$6.8	($5.4)	$0.0	$12.2	($0.8)	($0.2)	($1.5)	($2.1)	$10.1	1,543	105
3	5004/5005 Interface	Interface	500	($14.4)	($23.2)	$0.0	$8.8	$0.1	$1.1	$0.6	($0.4)	$8.5	513	241
4	AEP-DOM	Interface	500	$1.8	($6.2)	$0.0	$8.0	($0.1)	$0.4	($0.2)	($0.7)	$7.3	293	88
5	Bedington - Black Oak	Interface	500	($3.3)	($7.5)	$0.0	$4.2	$0.0	$0.0	$0.0	$0.0	$4.2	576	0
6	Wylie Ridge	Transformer	AP	($8.6)	($13.2)	$0.0	$4.6	($0.1)	$0.8	$0.5	($0.4)	$4.2	1,235	329
7	Wolfcreek	Transformer	AEP	($0.3)	($2.9)	$0.0	$2.6	($0.2)	($0.0)	($0.4)	($0.5)	$2.1	729	94
8	Baker - Broadford	Line	AEP	$0.2	($0.4)	$0.0	$0.6	$0.0	$1.2	($1.1)	($2.3)	($1.6)	8	20
9	West	Interface	500	($2.8)	($4.0)	$0.0	$1.3	$0.0	$0.0	$0.0	($0.0)	$1.3	231	12
10	Carnegie - Tidd	Line	AEP	($0.4)	($1.1)	$0.0	$0.6	$0.1	($0.0)	$0.4	$0.5	$1.2	323	202
11	Carnegie - Tidd	Line	AECO	($0.4)	($1.4)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	388	0
12	Susquehanna	Transformer	PPL	($1.2)	($2.0)	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	120	0
13	Benton Harbor - Palisades	Flowgate	Midwest ISO	$0.0	($0.3)	$0.0	$0.3	$0.0	$0.3	($0.2)	($0.5)	($0.2)	0	46
14	Crete - St Johns Tap	Flowgate	Midwest ISO	$4.9	$5.9	$0.0	($1.0)	($0.0)	($0.1)	$0.3	$0.4	($0.6)	1,456	398
15	Cloverdale - Lexington	Line	AEP	($1.1)	($1.4)	$0.0	$0.3	$0.8	$0.7	$0.2	$0.2	$0.5	173	155
20	Brues - West Bellaire	Line	AEP	$0.7	($0.0)	$0.0	$0.7	($0.4)	$0.5	($0.1)	($1.0)	($0.3)	79	71
23	Conesville Prep - Conesville	Line	AEP	($0.0)	($0.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	218	0
42	Kanawha - Kincaid	Line	AEP	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	18	0
43	Cloverdale - Ivy Hill	Line	AEP	$0.1	($0.1)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.1	24	18
46	Moseley - Roanoke	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	0	2

Table 7-46 AEP Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-44)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AEP-DOM	Interface	500	$7.5	($20.0)	$1.0	$28.4	($0.0)	($0.3)	$0.0	$0.3	$28.7	452	76
2	AP South	Interface	500	($13.8)	($37.4)	$0.2	$23.8	($3.1)	$1.3	$0.6	($3.8)	$19.9	1,255	735
3	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	10	74
4	5004/5005 Interface	Interface	500	($8.9)	($14.0)	($0.2)	$4.8	($0.6)	$0.8	$0.2	($1.2)	$3.7	806	294
5	Bedington - Black Oak	Interface	500	($2.9)	($6.1)	($0.0)	$3.1	($0.1)	($0.1)	$0.0	$0.0	$3.2	519	9
6	Kanawha River	Transformer	AEP	$2.1	($0.2)	$0.3	$2.6	$0.0	($0.0)	($0.0)	$0.0	$2.6	158	11
7	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	207	0
8	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
9	Sullivan	Transformer	AEP	($0.0)	($1.0)	($0.0)	$1.0	$0.0	$0.0	$0.0	($0.0)	$0.9	154	35
10	Mount Storm - Pruntytown	Line	AP	($0.4)	($1.2)	$0.0	$0.8	($0.2)	$0.1	$0.0	($0.3)	$0.5	87	64
11	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.4	$0.4	$0.0	($0.0)	($0.9)	($0.9)	($0.5)	556	110
12	East Frankfort - Crete	Line	ComEd	$2.6	$2.3	$0.4	$0.7	$0.1	($0.1)	($0.5)	($0.2)	$0.5	835	419
13	Rising	Flowgate	Midwest ISO	$0.3	$0.7	$0.0	($0.4)	$0.0	($0.0)	($0.0)	($0.0)	($0.4)	582	32
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.7	$0.4	($0.0)	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	142	3
15	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.1)	($0.0)	($0.3)	($0.3)	0	48
16	Ruth - Turner	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	18	11
17	Cloverdale - Lexington	Line	AEP	($0.7)	($0.8)	($0.0)	$0.0	($0.0)	$0.3	$0.1	($0.3)	($0.3)	154	97
19	Kammer	Transformer	AEP	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.1	($0.0)	($0.1)	$0.2	33	11
25	Sporn - Kyger Creek	Line	AEP	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	31	0
32	Kanawha River - Bradley	Line	AEP	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	7	0

AP Control Zone

Table 7-47 AP Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-45)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($11.6)	($46.2)	$0.0	$34.6	$2.2	$2.8	$4.8	$4.1	$38.7	1,172	513
2	Belmont	Transformer	AP	$11.5	($1.3)	$0.0	$12.8	($1.0)	($0.1)	($0.5)	($1.4)	$11.5	1,543	105
3	5004/5005 Interface	Interface	500	($14.8)	($22.6)	$0.0	$7.8	$1.0	$0.8	$2.4	$2.5	$10.3	513	241
4	Bedington - Black Oak	Interface	500	($2.2)	($10.3)	$0.0	$8.1	$0.0	$0.0	$0.0	$0.0	$8.1	576	0
5	Wylie Ridge	Transformer	AP	$4.9	$7.5	$0.0	($2.7)	($0.1)	($0.3)	($3.0)	($2.7)	($5.4)	1,235	329
6	AEP-DOM	Interface	500	($0.5)	($2.1)	$0.0	$1.6	$0.0	$0.0	$0.3	$0.3	$1.9	293	88
7	Wolfcreek	Transformer	AEP	$2.1	$3.3	$0.0	($1.2)	($0.2)	($0.1)	($0.3)	($0.3)	($1.6)	729	94
8	South Mahwah - Waldwick	Line	PSEG	($1.2)	($1.2)	$0.0	$0.1	$0.1	$0.2	($0.9)	($0.9)	($0.9)	1,730	203
9	Butler - Karns City	Line	AP	$1.4	$0.9	$0.0	$0.5	($0.1)	($0.3)	$0.0	$0.3	$0.8	369	44
10	Doubs	Transformer	AP	$0.3	($0.3)	$0.0	$0.6	$0.1	$0.1	$0.1	$0.1	$0.7	38	51
11	Carnegie - Tidd	Line	AECO	$0.8	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	388	0
12	Tiltonsville - Windsor	Line	AP	$1.3	$0.4	$0.0	$0.9	($0.1)	($0.0)	($0.2)	($0.3)	$0.6	223	45
13	Carnegie - Tidd	Line	AEP	$1.2	$0.3	$0.0	$0.9	($0.1)	($0.0)	($0.1)	($0.2)	$0.6	323	202
14	Hamilton - Weirton	Line	AP	$0.9	$0.3	$0.0	$0.6	$0.0	($0.0)	($0.0)	($0.0)	$0.6	138	3
15	West	Interface	500	($3.0)	($3.4)	$0.0	$0.4	$0.0	$0.0	$0.1	$0.1	$0.5	231	12
19	Collinsf - Osage	Line	AP	$0.2	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	54	0
22	Kingwood - Pruntytown	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	34	2
23	Bedington	Transformer	AP	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	10	5
27	Kingsfarm - Sony	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	($0.1)	0	2
28	Armstrong - Burma	Line	AP	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1	8	15

Table 7-48 AP Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-46)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($13.2)	($53.0)	($4.2)	$35.6	$2.3	$2.3	$4.5	$4.5	$40.1	1,255	735
2	Bedington - Black Oak	Interface	500	($2.0)	($8.6)	($0.2)	$6.3	$0.3	($0.1)	$0.1	$0.4	$6.7	519	9
3	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.3	$6.0	$0.2	($0.2)	($0.1)	$0.4	$6.4	452	76
4	5004/5005 Interface	Interface	500	($8.9)	($13.0)	($0.6)	$3.6	$0.4	$0.7	$0.4	$0.2	$3.7	806	294
5	Mount Storm - Pruntytown	Line	AP	($0.3)	($1.6)	($0.0)	$1.3	$0.2	($0.2)	$0.1	$0.4	$1.7	87	64
6	Tiltonsville - Windsor	Line	AP	$2.3	$0.7	$0.2	$1.8	($0.3)	($0.1)	($0.3)	($0.5)	$1.3	697	140
7	Harrisonburg - Endless Caverns	Line	Dominion	$0.7	$0.1	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	128	0
8	Albright - Snowy Creek	Line	AP	$0.6	($0.1)	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.0	$0.7	226	2
9	Pruntytown	Transformer	AP	$0.6	($0.1)	($0.0)	$0.7	($0.1)	($0.1)	$0.1	$0.1	$0.7	62	21
10	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($0.0)	($0.0)	$0.2	$0.2	$0.0	($0.0)	($0.7)	($0.7)	($0.5)	556	110
11	Nipetown - Reid	Line	AP	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	75	18
12	Endless Caverns	Transformer	Dominion	$0.4	$0.1	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	75	0
13	Dutch Fork - Windsor	Line	AP	$0.4	$0.1	$0.1	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	119	3
14	Hamilton - Weirton	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	86	12
15	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	($0.3)	454	36
17	Messic Road - Morgan	Line	AP	($0.3)	($0.6)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	172	0
19	Kingwood - Pruntytown	Line	AP	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	62	9
21	Middlebourne - Willow	Line	AP	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	58	0
22	Bedington - Shepherdstown	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
23	New Martinsville - Paden City	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.1)	($0.2)	($0.2)	23	26

ComEd Control Zone

Table 7-49 ComEd Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-47)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	Flowgate	Midwest ISO	($33.8)	($48.0)	($0.1)	$14.2	$3.8	$1.4	$3.2	$5.6	$19.7	1,456	398
2	AP South	Interface	500	($26.9)	($34.7)	$0.0	$7.8	$3.9	$0.9	$0.2	$3.3	$11.1	1,172	513
3	5004/5005 Interface	Interface	500	($20.9)	($27.0)	$0.0	$6.1	$1.6	$0.7	$0.4	$1.3	$7.4	513	241
4	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.2	($0.7)	$0.0	$0.8	($0.0)	($0.0)	($5.6)	($5.6)	($4.8)	593	140
5	Wylie Ridge	Transformer	AP	($12.4)	($16.0)	$0.0	$3.6	$1.4	$0.3	($0.1)	$1.0	$4.6	1,235	329
6	Lakeview - Pleasant Prairie	Flowgate	Midwest ISO	$0.2	$0.1	$0.0	$0.1	($0.1)	$0.0	($3.5)	($3.7)	($3.6)	24	164
7	Electric Jct - Nelson	Line	ComEd	$0.3	($5.0)	$0.0	$5.3	$0.0	$0.2	($2.5)	($2.7)	$2.6	447	39
8	Benton Harbor - Palisades	Flowgate	Midwest ISO	($0.7)	($0.9)	$0.0	$0.2	$0.8	($0.1)	$1.3	$2.3	$2.5	0	46
9	Bedington - Black Oak	Interface	500	($6.2)	($8.2)	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	576	0
10	Cherry Valley	Transformer	ComEd	$0.7	($1.2)	$0.0	$1.9	$0.0	$0.0	($0.1)	($0.1)	$1.8	325	10
11	West	Interface	500	($4.1)	($5.3)	$0.0	$1.2	$0.1	$0.0	$0.0	$0.1	$1.3	231	12
12	Pleasant Valley - Belvidere	Line	ComEd	($0.1)	($1.8)	$0.0	$1.7	$0.0	$0.1	($0.3)	($0.4)	$1.3	220	40
13	Belmont	Transformer	AP	($3.5)	($4.4)	($0.0)	$0.9	$0.3	$0.1	$0.1	$0.3	$1.2	1,543	105
14	Cloverdale - Lexington	Line	AEP	($1.2)	($1.6)	$0.0	$0.4	$1.2	$0.5	$0.1	$0.7	$1.1	173	155
15	Oak Grove - Galesburg	Flowgate	Midwest ISO	($0.1)	($0.4)	$0.0	$0.3	($0.0)	$0.2	($1.2)	($1.4)	($1.1)	52	62
19	East Frankfort - Crete	Line	ComEd	($1.4)	($2.2)	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	288	1
25	Belvidere - Woodstock	Line	ComEd	$0.0	($0.5)	$0.0	$0.5	($0.0)	$0.0	($0.1)	($0.1)	$0.4	68	12
28	Zion - Lakeview	Line	ComEd	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	166	0
31	Zion	Line	ComEd	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	432	0
32	Electric Junction - Aurora	Line	ComEd	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	14	0

Table 7-50 ComEd Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-48)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($28.0)	($43.6)	($0.3)	$15.4	($1.0)	$0.2	$0.0	($1.3)	$14.1	1,255	735
2	East Frankfort - Crete	Line	ComEd	($12.7)	($25.6)	($0.6)	$12.3	($2.0)	$0.6	$0.0	($2.5)	$9.8	835	419
3	5004/5005 Interface	Interface	500	($11.2)	($18.1)	($0.0)	$6.8	($0.3)	($0.2)	($0.0)	($0.2)	$6.7	806	294
4	AEP-DOM	Interface	500	($10.3)	($16.3)	($0.4)	$5.6	($0.1)	($0.2)	($0.0)	$0.1	$5.7	452	76
5	Rising	Flowgate	Midwest ISO	($1.9)	($5.8)	($0.0)	$3.9	($0.0)	($0.0)	$0.0	$0.0	$3.9	582	32
6	Bedington - Black Oak	Interface	500	($4.6)	($7.9)	($0.0)	$3.2	($0.0)	($0.0)	($0.0)	($0.0)	$3.2	519	9
7	Waterman - West Dekalb	Line	ComEd	($0.4)	($2.2)	$0.1	$1.9	$0.2	$0.2	($0.0)	($0.0)	$1.9	812	159
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($2.4)	($3.6)	($0.1)	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.1	142	3
9	Pleasant Valley - Belvidere	Line	ComEd	($0.6)	($2.7)	$0.1	$2.2	($0.1)	$0.8	($0.3)	($1.2)	$1.0	274	69
10	Tiltonsville - Windsor	Line	AP	($1.3)	($2.1)	($0.0)	$0.8	($0.0)	($0.0)	$0.0	$0.0	$0.8	697	140
11	Sammis - Wylie Ridge	Line	AP	($1.1)	($1.9)	($0.0)	$0.8	($0.0)	$0.0	$0.0	($0.1)	$0.7	305	37
12	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.6	($0.0)	($0.7)	($0.7)	0	82
13	Glidden - West Dekalb	Line	ComEd	($0.0)	($0.6)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	108	0
14	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.2	($2.7)	$0.6	$3.5	$0.3	$0.8	($2.4)	($2.9)	$0.6	556	110
15	Davis	Transformer	ComEd	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	55	0
25	Wilton Center	Transformer	ComEd	($0.3)	($0.4)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	23	6
31	Belvidere - Woodstock	Line	ComEd	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	7	0
36	Waukegan - Zion	Line	ComEd	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
49	Silver Lake	Transformer	ComEd	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
57	Powerton	Line	ComEd	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	23	0

DAY Control Zone

Table 7-51 DAY Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-49)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pierce - East Bend	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.4)	($0.4)	($0.4)	0	2
2	West	Interface	500	($0.2)	($0.5)	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	231	12
3	Cloverdale - Lexington	Line	AEP	($0.1)	($0.1)	$0.0	$0.0	$0.1	$0.4	$0.0	($0.3)	($0.3)	173	155
4	Wolfcreek	Transformer	AEP	($0.1)	($0.4)	$0.0	$0.3	$0.0	$0.0	$0.0	($0.0)	$0.2	729	94
5	AEP-DOM	Interface	500	($0.2)	($0.5)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	293	88
6	5004/5005 Interface	Interface	500	($1.6)	($1.6)	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	($0.2)	513	241
7	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	($0.2)	0	4
8	Bedington - Black Oak	Interface	500	($0.5)	($0.6)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	576	0
9	Branchburg - Flagtown	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.2)	0	0
10	Susquehanna	Transformer	PPL	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	120	0
11	Benton Harbor - Palisades	Flowgate	Midwest ISO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	46
12	Wylie Ridge	Transformer	AP	($0.9)	($1.2)	$0.0	$0.2	$0.0	$0.2	$0.1	($0.1)	$0.1	1,235	329
13	South Mahwah - Waldwick	Line	PSEG	($0.2)	($0.3)	$0.0	$0.1	$0.0	$0.1	$0.0	($0.0)	$0.1	1,730	203
14	Bristers - Ox	Line	Dominion	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.0	33	25
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.5	($0.0)	($0.1)	($0.0)	($0.0)	$0.1	$0.1	($0.0)	1,456	398
40	Foster2 - Pierce	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	1

Table 7-52 DAY Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-50)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($1.7)	($2.9)	($0.1)	$1.1	$0.1	$0.3	$0.1	($0.2)	$0.9	1,255	735
2	5004/5005 Interface	Interface	500	($0.6)	($1.4)	($0.0)	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	806	294
3	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	452	76
4	Bedington - Black Oak	Interface	500	($0.3)	($0.6)	($0.0)	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	519	9
5	East Frankfort - Crete	Line	ComEd	$0.1	$0.3	$0.0	($0.2)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	835	419
6	Tiltonsville - Windsor	Line	AP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	697	140
7	Sporn - Kyger Creek	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	31	0
8	Kanawha River	Transformer	AEP	($0.1)	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	158	11
9	Rising	Flowgate	Midwest ISO	$0.0	$0.1	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	582	32
10	Baker - Broadford	Line	AEP	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	($0.1)	($0.1)	10	74
11	Cloverdale - Lexington	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	154	97
12	Sammis - Wylie Ridge	Line	AP	($0.1)	($0.1)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	305	37
13	Kanawha - Kincaid	Line	AEP	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	207	0
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	142	3
15	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	556	110

DLCO Control Zone

Table 7-53 DLCO Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-51)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Wylie Ridge	Transformer	AP	($8.0)	($11.9)	($0.3)	$3.6	($0.4)	($0.1)	$0.2	($0.2)	$3.4	1,235	329
2	AP South	Interface	500	($8.2)	($11.0)	($0.2)	$2.7	($0.9)	($0.2)	$0.2	($0.5)	$2.2	1,172	513
3	Collier - Elwyn	Line	DLCO	$1.5	($0.1)	$0.0	$1.6	$0.0	($0.0)	($0.0)	$0.0	$1.7	189	16
4	Crescent	Transformer	DLCO	$1.1	($0.1)	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	106	0
5	5004/5005 Interface	Interface	500	($5.3)	($6.9)	($0.1)	$1.5	($0.4)	($0.0)	$0.1	($0.3)	$1.2	513	241
6	Bedington - Black Oak	Interface	500	($1.7)	($2.3)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	576	0
7	AEP-DOM	Interface	500	($0.6)	($1.0)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.3	293	88
8	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.0	$1.4	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	1,456	398
9	West	Interface	500	($0.9)	($1.1)	($0.0)	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	231	12
10	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	11	8
11	Beaver - Sammis	Line	DLCO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	$0.0	($0.2)	($0.2)	0	11
12	Butler - Karns City	Line	AP	($0.4)	($0.6)	($0.0)	$0.2	($0.0)	($0.0)	$0.0	($0.0)	$0.2	369	44
13	Elrama - Mitchell	Line	AP	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	95	17
14	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	17	0
15	East	Interface	500	($0.3)	($0.4)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	127	22
17	Arsenal - Oakland	Line	DLCO	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	24	6
57	Beaver - Mansfield	Line	DLCO	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
61	Brunot Island - Forbes	Line	DLCO	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
74	Brentwood - Elwyn	Unclassified	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
186	Bocgases	Transformer	DLCO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0

Table 7-54 DLCO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-52)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$5.1	($0.1)	$0.1	$5.3	($0.0)	($0.5)	($0.2)	$0.3	$5.6	310	58
2	AP South	Interface	500	($20.6)	($25.8)	($0.1)	$5.0	($0.9)	($0.2)	$0.2	($0.6)	$4.4	1,255	735
3	Collier - Elwyn	Line	DLCO	$1.9	$0.3	$0.1	$1.7	($0.0)	($0.1)	($0.0)	$0.0	$1.7	165	25
4	5004/5005 Interface	Interface	500	($7.4)	($8.9)	($0.1)	$1.5	($0.2)	($0.1)	$0.0	($0.1)	$1.4	806	294
5	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	452	76
6	Bedington - Black Oak	Interface	500	($3.4)	($4.3)	($0.0)	$0.9	($0.1)	($0.1)	$0.0	($0.0)	$0.8	519	9
7	Sammis - Wylie Ridge	Line	AP	($1.3)	($2.1)	($0.0)	$0.8	($0.1)	$0.1	$0.0	($0.2)	$0.6	305	37
8	East Frankfort - Crete	Line	ComEd	$0.6	$1.0	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$0.0	($0.4)	835	419
9	Baker - Broadford	Line	AEP	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	($0.0)	($0.0)	($0.1)	($0.1)	10	74
10	Collier	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.1	$0.1	0	5
11	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	142	3
12	Mount Storm - Pruntytown	Line	AP	($0.7)	($0.9)	($0.0)	$0.2	($0.1)	$0.0	$0.0	($0.1)	$0.0	87	64
13	Kanawha River	Transformer	AEP	($0.1)	($0.2)	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	$0.0	158	11
14	Dutch Fork - Windsor	Line	AP	($0.1)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	119	3
15	Cloverdale - Lexington	Line	AEP	($0.1)	($0.2)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	154	97
21	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
40	Arsenal - Brunot Island	Line	DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	11	8
54	Cheswick - Logan's Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
183	Bocgases	Transformer	DLCO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-55 Dominion Control Zone top congestion cost impacts (By facility): January through March 2011 (See 2010 SOM, Table 7-53)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$28.0	($18.1)	$0.5	$46.6	$0.3	$3.9	($0.6)	($4.2)	$42.4	1,172	513
2	Bedington - Black Oak	Interface	500	$6.1	$2.8	$0.5	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	576	0
3	AEP-DOM	Interface	500	$2.9	$1.4	$0.3	$1.8	($0.1)	($0.2)	($0.1)	($0.0)	$1.8	293	88
4	Wylie Ridge	Transformer	AP	$3.3	$1.8	$0.4	$1.8	$0.0	($0.1)	($0.3)	($0.2)	$1.6	1,235	329
5	Crete - St Johns Tap	Flowgate	Midwest ISO	$2.9	$1.4	$0.1	$1.5	($0.1)	($0.1)	($0.0)	$0.0	$1.6	1,456	398
6	Bristers - Ox	Line	Dominion	($0.1)	($1.6)	$0.0	$1.5	$0.2	$0.2	($0.0)	($0.0)	$1.4	33	25
7	Cloverdale - Lexington	Line	AEP	$1.6	$0.6	$0.2	$1.2	($0.1)	($0.3)	($0.4)	($0.3)	$0.9	173	155
8	Chesterfield - Turner	Line	Dominion	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	23	0
9	Clover	Transformer	Dominion	$0.4	($0.3)	$0.2	$0.8	($0.1)	$0.2	($0.1)	($0.4)	$0.5	148	41
10	Susquehanna	Transformer	PPL	($1.0)	($0.6)	($0.1)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	120	0
11	East	Interface	500	($0.8)	($0.5)	($0.0)	($0.3)	$0.0	$0.1	$0.0	($0.1)	($0.4)	127	22
12	Valley	Transformer	Dominion	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	5	0
13	South Mahwah - Waldwick	Line	PSEG	($0.5)	($0.4)	$0.2	$0.1	$0.1	$0.1	($0.3)	($0.4)	($0.3)	1,730	203
14	Beechwood - Kerr Dam	Line	Dominion	$0.1	($0.2)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	8	0
15	Burches Hill	Transformer	Pepco	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)	$0.1	$0.0	($0.2)	($0.2)	8	44
20	Harrisonburg - Endless Caverns	Line	Dominion	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	17	0
21	Chaparral - Carson	Line	Dominion	$0.1	($0.0)	$0.0	$0.2	($0.1)	$0.1	($0.2)	($0.3)	($0.1)	29	32
22	Margarettsville - Seaboard	Line	Dominion	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1	0
32	Dow Tap - Leehall	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	10	0
40	Lexington	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	111	0

Table 7-56 Dominion Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2010 SOM, Table 7-54)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$38.6	($18.8)	($0.1)	$57.3	$2.4	$4.3	$0.2	($1.7)	$55.6	1,255	735
2	AEP-DOM	Interface	500	$14.9	$12.1	$0.6	$3.4	($0.1)	($0.3)	($0.0)	$0.1	$3.5	452	76
3	Bedington - Black Oak	Interface	500	$6.0	$3.3	$0.3	$3.1	$0.0	$0.1	($0.0)	($0.1)	$3.0	519	9
4	5004/5005 Interface	Interface	500	($1.1)	($2.1)	$0.1	$1.1	$0.2	$0.2	$0.0	$0.1	$1.2	806	294
5	Cloverdale - Lexington	Line	AEP	$1.2	$0.5	$0.2	$0.9	($0.2)	($0.5)	($0.3)	($0.0)	$0.8	154	97
6	East Frankfort - Crete	Line	ComEd	$1.5	$0.9	$0.1	$0.7	($0.1)	($0.3)	($0.1)	($0.0)	$0.7	835	419
7	Dickerson - Pleasant View	Line	Pepco	$0.5	$0.0	($0.0)	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	53	3
8	Harrisonburg - Endless Caverns	Line	Dominion	$0.0	($0.5)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	128	0
9	Baker - Broadford	Line	AEP	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.6)	($0.0)	$0.4	$0.4	10	74
10	Inwood - Stonewall	Line	AP	$0.1	($0.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	159	0
11	Tiltonsville - Windsor	Line	AP	$0.4	$0.2	$0.1	$0.2	$0.0	($0.0)	($0.1)	($0.0)	$0.2	697	140
12	Sammis - Wylie Ridge	Line	AP	$0.5	$0.3	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	305	37
13	Messic Road - Morgan	Line	AP	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
14	Nipetown - Reid	Line	AP	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	75	18
15	Millville - Old Chapel	Line	AP	$0.0	($0.2)	($0.0)	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	41	6
16	Crozet - Dooms	Line	Dominion	$0.1	($0.1)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3	0
18	Fredericksburg	Transformer	Dominion	($0.0)	($0.3)	($0.0)	$0.3	($0.0)	$0.1	($0.0)	($0.1)	$0.2	29	53
20	Endless Caverns	Transformer	Dominion	($0.0)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	75	0
21	Bristers - Ox	Line	Dominion	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	2	4
22	Edinburg	Transformer	Dominion	$0.1	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	30	1

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2011 Quarterly State of the Market Report for PJM: January through March* focuses on the Monthly Balance of Planning Period FTR Auctions during the 2010 to 2011 planning period, which is June 1, 2010, through May 31, 2011.

1 87 FERC ¶ 61,054 (1999).

Table 8-1 The FTR Auction Markets results were competitive

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

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti competitive behavior in 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.

Highlights

- FTRs were paid at 87.9 percent of the target allocation level for the 2010 to 2011 planning period through March 31, 2011.
- 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.
- There were no transactions in the secondary bilateral FTR obligation market for the first three months of 2011.
- 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.

Recommendations

- 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.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The most recent Long Term FTR Auction was conducted during the 2010 to 2011 planning period and covers three consecutive planning periods between 2011 and 2014. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2010 through March 2011) of the 2010 to 2011 planning period, there were 3,622,316 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2010 through March 2011) of the 2010 to 2011 planning period, total FTR buy bids were 12,615,413 MW. This is a 72 percent increase from 7,354,546 MW for the first ten months (June 2009 through March 2010) of the 2009 to 2010 planning period.

- **FTR Credit Issues.** There were no participants that defaulted during the first three months of 2011.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the Monthly Balance of Planning Period Auctions for the first three months of 2011 was low for peak and off peak FTR obligations and highly concentrated for 24-hour FTR obligations. The ownership concentration was also highly concentrated for 24-hour, peak and off peak FTR buy bid options for the same time period. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. Financial entities purchased 85 percent of prevailing flow and 86 percent of counter flow FTRs in the Monthly Balance of Planning Period Auctions for the first three months of 2011. Overall, financial entities purchased 86 percent of all Monthly Balance of Planning Period cleared buy bid FTRs during the same time period. The net position of all FTRs, including all auctions, is calculated for every organization each day. The organization's net position is the difference between all FTR buys and FTR sells from all relevant auctions and bilateral trades for each day. The data is summarized for the first three months of 2011 to show ownership patterns by FTR direction. Physical entities owned 39 percent of all prevailing and counter flow FTRs, including 43 percent of all prevailing flow and 28 percent of all counter flow FTRs. Financial entities owned 61 percent of all prevailing and counter flow FTRs, including 57 percent of all prevailing flow FTRs and 72 percent of all counter flow FTRs and during the same time period.

Market Performance

- **Volume.** For the first ten months of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,681,158 MW (13.3 percent) of FTR buy bids and 404,777 MW (11.2 percent) of FTR sell offers. This is an increase from the first ten months of the 2009 to 2010 planning period, where the Monthly Balance of Planning Period FTR Auctions cleared 820,498 MW (11.2 percent) of FTR buy bids and 229,394 MW (9.0 percent) of FTR sell offers.

- **Price.** The weighted-average price paid for buy bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first three months of 2011 was $0.12 per MWh, compared to $0.15 per MWh for the first three months of 2010.

- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $22.4 million in net revenue for all FTRs during the first ten months of the 2010 to 2011 planning period. This is a $4.5 million increase from the comparable time period in the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 96.9 percent revenue adequate for the 2009 to 2010 planning period. FTRs were paid at 87.9 percent of the target allocation level for the first ten months of the 2010 to 2011 planning period. The Market Implementation Committee (MIC) approved the creation of the Financial Transmission Rights Task Force (FTRTF) to investigate the causes of the FTR revenue inadequacy that occurred in the 2010 to 2011 Planning Period and identify potential improvements that could be made to minimize the revenue inadequacy going forward.[2] Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,354.5 million of FTR revenues during the first ten months of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the first ten months of the 2010 to 2011 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and PECO Control Zone, respectively.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall and were profitable for both physical entities and financial entities in the first three months of 2011.

Auction Revenue Rights

Market Structure

- **Supply and Demand.** ARRs are assigned only for the annual delivery periods.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. In the first ten months of the 2010 to 2011 planning period, 48,637 MW of ARRs were reassigned, an increase of 153 percent (29,407 MW) from the 19,230 MW of ARRs reassigned in the 2009 to 2010 planning period. The reassigned ARRs were associated with approximately $970,400 of revenue, an increase of 158 percent from the $375,800 of revenue that were reassigned for the full 2009 to 2010 planning period.

Market Performance

- **Revenue Adequacy.** During the 2010 to 2011 planning period, ARR holders will receive $1,029.3 million in ARR credits, with an average hourly ARR credit of $1.15 per MWh. During the 2010 to 2011 planning period, the ARR target allocations were $1,029.3 million while PJM collected $1,097.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through March 2011, making ARRs revenue adequate. During the 2009 to 2010 planning period, ARR holders received $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. For the 2009 to 2010 planning period, the ARR target allocations were $1,273.6 million while PJM collected $1,368.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

2 PJM Financial Transmission Rights Task Force (FTRTF), <http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The effectiveness of ARRs as a hedge can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The effectiveness of ARRs and FTRs as a hedge against congestion can be measured by comparing the revenue received by ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market. For the 2009 to 2010 planning period, all ARRs and FTRs hedged more than 96.2 percent of the congestion costs within PJM. During the first ten months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 97.4 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs and FTRs can also be measured by comparing the value of the ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs and FTRs. The total value of ARRs plus FTRs was 4.0 percent of the total real time energy charges in the first three months of 2011.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with the opportunity to hedge positions or to speculate. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2010 to 2011 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

FTRs were paid at 87.9 percent of the target allocation level for the first ten months of the 2010 to 2011 planning period. Revenue adequacy for a planning period is not final until the end of the period.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased.

The total of ARR and FTR revenues hedged more than 97.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2010 to 2011 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Patterns of Ownership

Table 8-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through March 2011 (See 2010 SOM, Table 8-6)

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	14.6%	14.2%	14.5%
	Financial	85.4%	85.8%	85.5%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	37.7%	30.9%	36.6%
	Financial	62.3%	69.1%	63.4%
	Total	100.0%	100.0%	100.0%

Table 8-3 Daily FTR net position ownership by FTR direction: January through March 2011 (See 2010 SOM, Table 8-7)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	42.7%	27.5%	38.8%
Financial	57.3%	72.5%	61.2%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-4 Monthly Balance of Planning Period FTR Auction market volume: January through March 2011 (See 2010 SOM, Table 8-11)

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-11	Obligations	Buy bids	189,084	1,101,808	164,743	15.0%	937,065	85.0%
		Sell offers	50,981	261,888	28,189	10.8%	233,699	89.2%
	Options	Buy bids	1,040	105,293	8,691	8.3%	96,602	91.7%
		Sell offers	2,927	43,161	12,380	28.7%	30,781	71.3%
Feb-11	Obligations	Buy bids	185,625	1,090,475	181,977	16.7%	908,497	83.3%
		Sell offers	41,609	220,079	20,957	9.5%	199,122	90.5%
	Options	Buy bids	959	93,909	9,372	10.0%	84,537	90.0%
		Sell offers	2,555	33,140	9,643	29.1%	23,497	70.9%
Mar-11	Obligations	Buy bids	192,349	1,154,132	216,165	18.7%	937,967	81.3%
		Sell offers	48,727	256,121	30,492	11.9%	225,629	88.1%
	Options	Buy bids	1,026	96,152	7,254	7.5%	88,898	92.5%
		Sell offers	2,351	41,200	10,587	25.7%	30,613	74.3%
2009/2010*	Obligations	Buy bids	1,908,766	8,003,573	946,107	11.8%	7,057,466	88.2%
		Sell offers	649,057	2,337,381	181,810	7.8%	2,155,571	92.2%
	Options	Buy bids	4,904	216,423	17,194	7.9%	199,228	92.1%
		Sell offers	29,328	458,584	72,335	15.8%	386,248	84.2%
2010/2011**	Obligations	Buy bids	2,090,066	11,298,761	1,621,495	14.4%	9,677,266	85.6%
		Sell offers	644,226	3,105,812	275,918	8.9%	2,829,894	91.1%
	Options	Buy bids	14,412	1,316,652	59,663	4.5%	1,256,989	95.5%
		Sell offers	57,073	516,504	128,859	24.9%	387,646	75.1%

* Shows Twelve Months for 2009/2010; ** Shows ten months ended 31-Mar-2011 for 2010/2011

Table 8-5 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through March 2011 (See 2010 SOM, Table 8-12)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	Bid	677,552	197,260	140,265				192,024	1,207,101
	Cleared	134,232	18,200	8,548				12,454	173,434
Feb-11	Bid	705,015	157,482	139,776				182,111	1,184,383
	Cleared	156,562	11,243	11,107				12,438	191,350
Mar-11	Bid	774,291	206,225	205,539				64,228	1,250,283
	Cleared	173,607	22,830	20,602				6,380	223,419

Table 8-6 Secondary bilateral FTR market volume: Planning periods 2009 to 2010 and 2010 to 2011[3] (See 2010 SOM, Table 8-13)

Planning Period	Hedge Type	Class Type	Volume (MW)
2009/2010	Obligation	24-Hour	1,535
		On Peak	3,979
		Off Peak	4,132
		Total	9,646
	Option	24-Hour	30
		On Peak	0
		Off Peak	0
		Total	30
2010/2011*	Obligation	24-Hour	1,729
		On Peak	10,573
		Off Peak	12,740
		Total	25,042
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20

* Shows ten months ended 31-Mar-2011

Price

Table 8-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through March 2011 (See 2010 SOM, Table 8-16)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-11	$0.13	$0.36	$0.02				$0.28	$0.17
Feb-11	$0.08	$0.13	$0.11				$0.18	$0.10
Mar-11	$0.09	$0.16	$0.15				$0.04	$0.09

3 The 2010 to 2011 planning period covers bilateral FTRs that are effective for any time between June 1, 2010 through March 31, 2011, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 8-8 Monthly Balance of Planning Period FTR Auction revenue: January through March 2011 (See 2010 SOM, Table 8-19)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-11	Obligations	Buy bids	($1,205,888)	$7,104,026	$6,539,294	$12,437,433
		Sell offers	$1,138,221	$2,625,465	$4,050,289	$7,813,975
	Options	Buy bids	$0	$136,353	$87,800	$224,153
		Sell offers	$0	$1,812,131	$686,209	$2,498,340
Feb-11	Obligations	Buy bids	($36,220)	$4,296,859	$3,345,841	$7,606,480
		Sell offers	$587,026	$1,938,472	$2,305,072	$4,830,570
	Options	Buy bids	$0	$126,188	$25,671	$151,859
		Sell offers	$1,947	$1,218,343	$389,391	$1,609,682
Mar-11	Obligations	Buy bids	($101,074)	$4,605,081	$3,368,274	$7,872,281
		Sell offers	$423,197	$2,274,909	$1,933,265	$4,631,371
	Options	Buy bids	$14,085	$292,986	$178,090	$485,161
		Sell offers	$5,149	$1,231,751	$454,338	$1,691,239
2009/2010*	Obligations	Buy bids	($121,010)	$45,775,003	$33,593,366	$79,247,359
		Sell offers	$3,920,764	$21,760,177	$17,779,192	$43,460,133
	Options	Buy bids	$98,620	$1,940,920	$834,871	$2,874,411
		Sell offers	$263,053	$11,631,451	$7,274,458	$19,168,962
2010/2011**	Obligations	Buy bids	$3,474,374	$67,873,636	$50,551,542	$121,899,552
		Sell offers	$7,646,424	$32,826,512	$28,525,928	$68,998,864
	Options	Buy bids	$37,176	$2,518,437	$1,861,753	$4,417,367
		Sell offers	$1,874,407	$19,210,762	$13,861,271	$34,946,439

* Shows twelve Months for 2009/2010; ** Shows ten months ended 31-Mar-2011 for 2010/2011

Figure 8-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Figure 8-7)

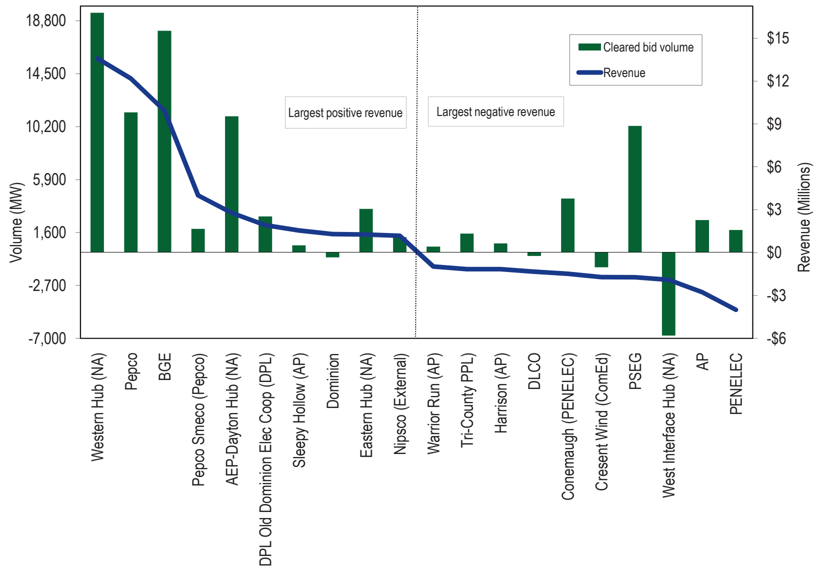
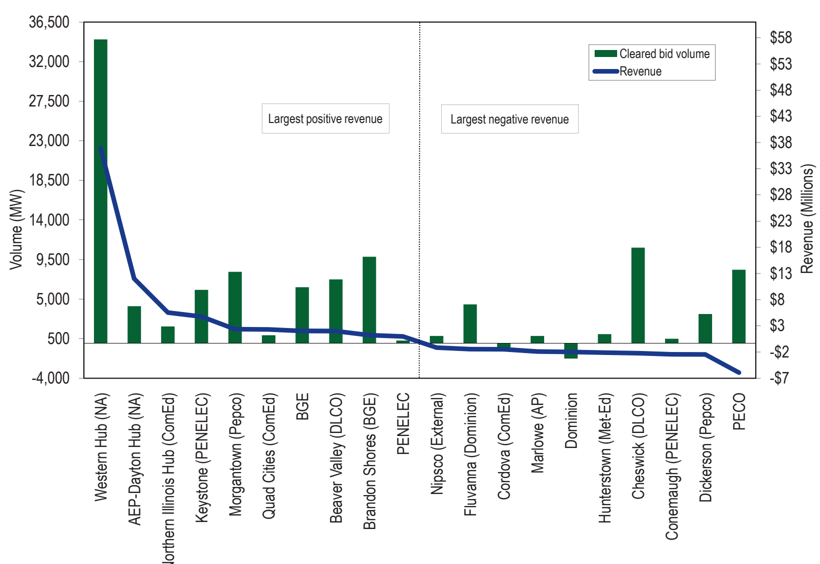


Figure 8-2 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Figure 8-8)



Revenue Adequacy

Table 8-9 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011 (See 2010 SOM, Table 8-20)

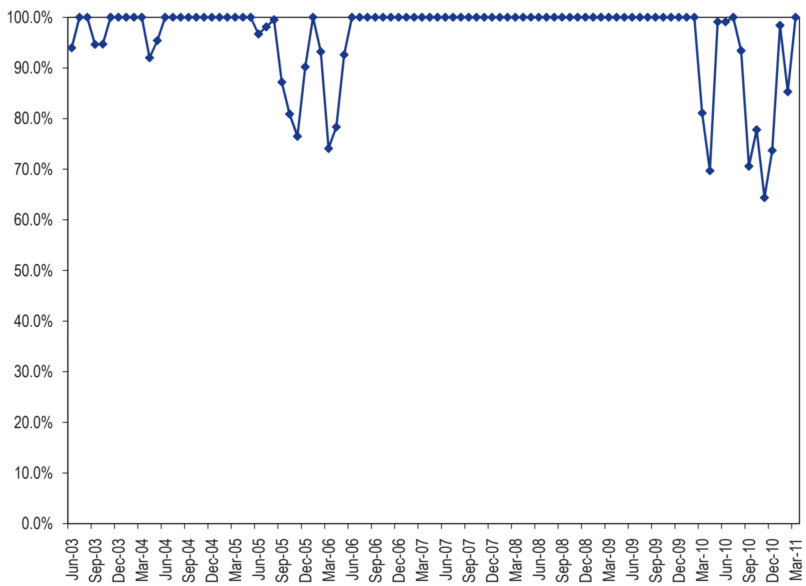
Accounting Element	2009/2010	2010/2011*
ARR information		
ARR target allocations	$1,276.9	$858.3
FTR auction revenue	$1,368.7	$913.3
ARR excess	$91.9	$55.0
FTR targets		
FTR target allocations	$908.1	$1,541.8
Adjustments:		
Adjustments to FTR target allocations	($1.5)	($1.7)
Total FTR targets	$906.6	$1,540.1
FTR revenues		
ARR excess	$91.9	$55.0
Competing uses	$0.0	$0.1
Congestions		
Net Negative Congestion (enter as negative)	($37.8)	($38.5)
Hourly congestion revenue	$854.9	$1,369.6
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($31.0)	($32.8)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($2.0)	($0.8)
Adjustments:		
Excess revenues carried forward into future months	$27.3	$0.0
Excess revenues distributed back to previous months	$9.3	$4.6
Other adjustments to FTR revenues	$2.4	$0.4
Total FTR revenues	$923.5	$1,357.7
Excess revenues distributed to other months	($45.1)	($4.6)
Net Negative Congestion charged to DA Operating Reserves	$0.0	$1.4
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$878.4	$1,354.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$880.3	$1,355.3
Remaining deficiency	$28.3	$185.6

* Shows ten months ended 31-Mar-11

Table 8-10 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Table 8-21)

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-10	$194.2	$196.1	97.8%	$194.2	99.0%	($1.9)
Jul-10	$275.0	$273.0	100.0%	$273.0	100.0%	$0.0
Aug-10	$111.3	$119.2	93.2%	$111.3	93.4%	($7.9)
Sep-10	$116.7	$165.3	70.0%	$116.7	70.6%	($48.6)
Oct-10	$52.4	$67.4	77.4%	$52.4	77.8%	($14.9)
Nov-10	$51.5	$80.0	61.9%	$51.5	64.4%	($28.5)
Dec-10	$184.9	$251.1	73.2%	$184.9	73.6%	($66.2)
Jan-11	$245.4	$249.5	98.3%	$245.4	98.4%	($4.0)
Feb-11	$79.4	$93.0	85.0%	$79.4	85.4%	($13.6)
Mar-11	$48.2	$45.7	100.0%	$45.7	100.0%	$0.0
Summary for Planning Period 2010 to 2011 through March 31, 2011						
Total	$1,354.5	$1,540.1		$1,354.5	87.9%	($185.6)

Figure 8-3 FTR payout ratio by month: June 2003 to March 2011[4] (See 2010 SOM, Figure 8-9)



4 The underlying data for Figure 8-3 and Table 8-11 is from the "FTR Credit" spreadsheet posted on PJM's website at http://www.pjm.com/markets-and-operations/ftr/revenue-adequacy.aspx and accessed on April 15, 2011.

Table 8-11 FTR payout ratio by planning period (See 2010 SOM, Table 8-22)

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011*	87.9%

* through March 31, 2011

Figure 8-4 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Figure 8-10)

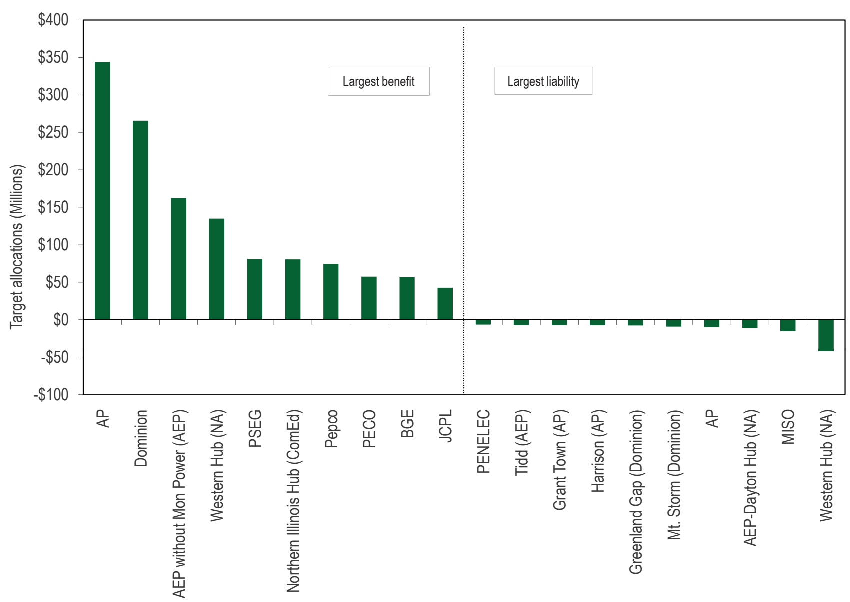
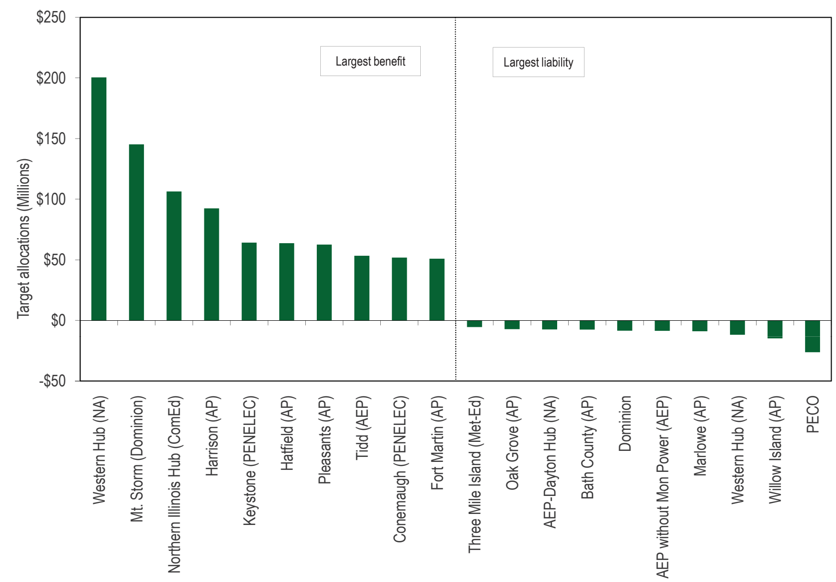


Figure 8-5 Ten largest positive and negative FTR target allocations summed by source: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Figure 8-11)



Profitability

Table 8-12 FTR profits by organization type and FTR direction: January through March 2011 (See 2010 SOM, Table 8-23)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	$185,895,964	($10,987,905)	$174,908,059
Financial	$34,280,070	$22,742,475	$57,022,545
Total	$220,176,035	$11,754,569	$231,930,604

Table 8-13 Monthly FTR profits by organization type: January through March 2011 (See 2010 SOM, Table 8-24)

	Organization Type		
Month	Physical	Financial	Total
Jan	$143,676,404	$36,993,105	$180,669,509
Feb	$41,840,764	$7,212,012	$49,052,776
Mar	($10,609,108)	$12,817,427	$2,208,319
Total	$174,908,059	$57,022,545	$231,930,604

Auction Revenue Rights

Market Structure

ARR Reassignment for Retail Load Switching

Table 8-14 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through March 31, 2011 (See 2010 SOM, Table 8-28)

	ARRs Reassigned (MW)		ARR Revenue Reassigned [Dollars (Thousands)]	
Control Zone	2009/2010 (12 months)	2010/2011 (10 months)*	2009/2010 (12 months)	2010/2011 (10 months)*
AECO	417	733	$7.6	$5.2
AEP	268	634	$6.3	$14.4
AP	629	4,839	$76.9	$466.7
BGE	3,162	3,228	$63.2	$48.7
ComEd	3,145	2,592	$10.1	$54.7
DAY	21	161	$0.1	$0.5
DLCO	371	1,701	$1.0	$7.9
Dominion	0	0	$0.0	$0.0
DPL	952	1,032	$10.9	$9.4
JCPL	1,151	3,304	$19.3	$27.2
Met-Ed	33	3,843	$0.8	$50.6
PECO	29	11,963	$0.5	$86.9
PENELEC	8	3,614	$0.2	$51.7
Pepco	2,511	2,315	$25.5	$25.6
PPL	4,489	5,380	$103.7	$70.8
PSEG	1,984	3,166	$49.6	$50.0
RECO	62	134	$0.0	$0.1
Total	19,230	48,637	$375.8	$970.4

* Through 31-Mar-11

Revenue Adequacy

Table 8-15 ARR revenue adequacy (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011[5] (See 2010 SOM, Table 8-30)

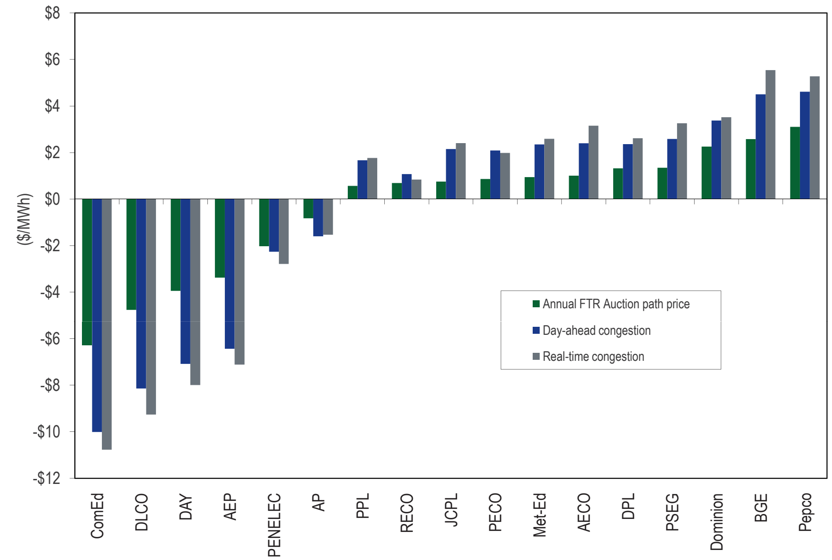
	2009/2010	2010/2011
Total FTR auction net revenue	$1,368.3	$1,097.0
Long Term FTR Auction net revenue	$19.8	$23.9
Annual FTR Auction net revenue	$1,329.1	$1,050.7
Monthly Balance of Planning Period FTR Auction net revenue*	$19.4	$22.4
ARR target allocations	$1,273.6	$1,029.3
ARR credits	$1,273.6	$1,029.3
Surplus auction revenue	$94.6	$67.7
ARR payout ratio	100%	100%
FTR payout ratio*	96.9%	87.9%

* Shows twelve months for 2009/2010 and ten months ended 31-Mar-11 for 2010/2011

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-6 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2010 to 2011 through Mar 31, 2011 (See 2010 SOM, Figure 8-12)



5 Table 8-15 has been updated from prior *State of the Market Reports* to include the net revenue for applicable FTRs from the Long Term FTR Auctions.

Effectiveness of ARRs as a Hedge against Congestion

Table 8-16 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Table 8-31)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$5,622,671	$1,310,021	$6,932,692	$44,349,044	($37,416,353)	15.6%
AEP	$8,853,266	$152,660,243	$161,513,509	$200,659,883	($39,146,374)	80.5%
AP	$35,547,112	$299,790,457	$335,337,569	$89,628,324	$245,709,245	>100%
BGE	$29,986,713	$4,608,689	$34,595,402	$51,278,903	($16,683,501)	67.5%
ComEd	$82,312,055	$10,797,459	$93,109,514	($234,877,922)	$327,987,436	>100%
DAY	$3,657,086	$2,472,770	$6,129,856	$12,127,230	($5,997,374)	50.5%
DLCO	$5,052,309	$0	$5,052,309	$38,350,629	($33,298,320)	13.2%
Dominion	$4,991,988	$215,247,421	$220,239,409	$11,833,868	$208,405,541	>100%
DPL	$11,862,147	$1,700,240	$13,562,387	$66,369,256	($52,806,869)	20.4%
JCPL	$15,966,837	$3,343,027	$19,309,864	$69,203,351	($49,893,487)	27.9%
Met-Ed	$13,272,652	$801,019	$14,073,671	$30,409,973	($16,336,302)	46.3%
PECO	$1,707,188	$41,177,753	$42,884,941	($39,784,213)	$82,669,154	>100%
PENELEC	$23,696,177	$15,027	$23,711,204	$62,272,710	($38,561,506)	38.1%
Pepco	$20,673,905	$2,088,944	$22,762,849	$159,029,806	($136,266,957)	14.3%
PJM	$17,922,362	$3,740,741	$21,663,103	$23,084,200	($1,421,097)	93.8%
PPL	$20,247,335	$5,702,692	$25,950,027	$68,570,322	($42,620,295)	37.8%
PSEG	$38,443,768	$8,184,471	$46,628,239	($1,845,175)	$48,473,415	>100%
RECO	$93,249	$0	$93,249	$3,028,127	($2,934,878)	3.1%
Total	$339,908,820	$753,640,974	$1,093,549,794	$653,688,314	$439,861,480	>100%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-17 ARR and FTR congestion hedging by control zone: Planning period 2010 to 2011 through March 31, 2011 (See 2010 SOM, Table 8-32)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$6,095,666	$14,480,278	$8,345,440	$12,230,504	$32,287,792	($20,057,288)	37.9%
AEP	$194,446,396	$179,024,056	$191,900,881	$181,569,571	$153,180,035	$28,389,536	>100%
AP	$308,392,416	$310,779,096	$266,150,349	$353,021,163	$259,568,046	$93,453,117	>100%
BGE	$33,678,997	$74,941,933	$47,382,877	$61,238,053	$82,658,914	($21,420,861)	74.1%
ComEd	$91,566,097	$86,902,493	$81,800,781	$96,667,809	$238,543,928	($141,876,119)	40.5%
DAY	$5,788,157	$1,620,109	$1,889,950	$5,518,316	$5,415,642	$102,674	>100%
DLCO	$5,052,309	$3,476,479	($4,550,195)	$13,078,983	$20,119,944	($7,040,961)	65.0%
Dominion	$176,257,284	$247,157,883	$183,588,232	$239,826,935	$252,964,141	($13,137,206)	94.8%
DPL	$12,954,039	$28,140,656	$20,851,094	$20,243,601	$53,185,771	($32,942,170)	38.1%
JCPL	$18,916,996	$48,991,028	$22,844,329	$45,063,695	$60,326,293	($15,262,598)	74.7%
Met-Ed	$13,935,697	$18,491,275	$7,882,099	$24,544,873	$3,492,650	$21,052,223	>100%
PECO	$23,365,352	$62,541,602	$30,892,149	$55,014,805	($5,915,109)	$60,929,914	>100%
PENELEC	$23,704,470	$55,784,419	$30,540,639	$48,948,250	$91,265,200	($42,316,950)	53.6%
Pepco	$22,895,504	$119,681,619	$123,451,330	$19,125,793	$84,951,923	($65,826,130)	22.5%
PJM	$20,706,621	($4,041,689)	($7,370,837)	$24,035,769	($6,109,734)	$30,145,503	>100%
PPL	$27,383,200	$29,454,400	$18,118,020	$38,719,580	$908,182	$37,811,398	>100%
PSEG	$44,042,595	$80,159,128	$73,296,235	$50,905,488	$4,175,919	$46,729,569	>100%
RECO	$93,249	($1,584,318)	($1,299,786)	($191,283)	$4,450,508	($4,641,791)	0.0%
Total	$1,029,275,045	$1,356,000,448	$1,095,713,587	$1,289,561,906	$1,335,470,045	($45,908,139)	96.6%

Table 8-18 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011[6] (See 2010 SOM, Table 8-33)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2009/2010	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%
2010/2011*	$858,274,100	$1,356,000,446	$913,291,441	$1,300,983,106	$1,335,470,043	($34,486,937)	97.4%

* Shows ten months ended 31-Mar-11

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-19 ARRs and FTRs as a hedge against energy charges by control zone: January through March 2011 (See 2010 SOM, Table 8-34)

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$1,717,556	$2,161,395	$3,878,951	$138,045,110	2.8%
AEP	$46,975,152	$2,459,339	$49,434,490	$1,391,430,768	3.6%
AP	$79,466,492	$5,267,398	$84,733,890	$579,568,681	14.6%
BGE	$8,518,116	($7,054,555)	$1,463,561	$454,670,031	0.3%
ComEd	$22,545,926	($4,451,644)	$18,094,282	$866,205,482	2.1%
DAY	$1,647,509	($658,242)	$989,267	$168,505,772	0.6%
DLCO	$1,245,775	$113,530	$1,359,305	$135,200,549	1.0%
Dominion	$55,649,859	$1,231,809	$56,881,668	$1,242,792,880	4.6%
DPL	$3,191,903	$3,167,520	$6,359,423	$255,900,862	2.5%
JCPL	$4,210,545	$13,805,301	$18,015,846	$302,077,306	6.0%
Met-Ed	$3,272,105	$1,570,973	$4,843,078	$202,216,285	2.4%
PECO	$17,814,978	$6,555,425	$24,370,403	$540,978,873	4.5%
PENELEC	$5,846,893	($3,625,903)	$2,220,990	$212,400,115	1.0%
Pepco	$5,401,901	($8,639,879)	($3,237,979)	$418,374,513	(0.8%)
PJM	$5,635,457	$675,452	$6,310,909	NA	NA
PPL	$5,025,482	$18,347,083	$23,372,566	$589,122,253	4.0%
PSEG	$13,254,909	$16,553,303	$29,808,212	$578,740,424	5.2%
RECO	$22,993	($558,822)	($535,829)	$17,258,551	(3.1%)
Total	$281,443,550	$46,919,483	$328,363,033	$8,107,952,612	4.0%

6 The FTR credits do not include after-the-fact adjustments. For the 2010 to 2011 planning period, the ARR credits were the total credits allocated to all ARR holders for the first ten months (June 2010 through March 2011) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first ten months of this planning period and the portion of Annual FTR Auction revenue distributed to the first ten months.